Pathway to 2030

Industry Code, Standard and Licence Recommendation Report

July 2022

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Contents

1 Introduction

We have worked with stakeholders to identify potential changes required to the relevant industry codes, standards and licences to facilitate the Holistic Network Design (HND) recommendations.

It is likely that changes will be required to the current industry codes and standards to enable the successful implementation of the HND. We have set out our initial views on the key barriers and enablers to the successful implementation of the HND and outlined the potential changes that are likely required to the relevant industry codes, standards, and licences. We have set this out in the context of the minded-to decisions from Ofgem related to the Early Opportunities workstream[1] and the preferred offshore delivery model related to the Pathway to 2030 (PT2030) workstream[2].

This new coordinated approach seeks to facilitate more anticipatory investment, speed up the delivery of associated onshore grid infrastructure and bring forward connection dates for offshore wind projects. It is likely that changes will be required to the current industry codes and standards to enable the successful implementation of the HND. This is because the current arrangements have only needed to accommodate radial connections from individual offshore wind farms to the National Electricity Transmission System, as opposed to the delivery and use of shared offshore transmission infrastructure which the HND recommends.

This report is one out of a suite of seven documents forming the PT2030 Publication Package. It seeks to deliver on the Department for Business, Energy, and Industrial Strategy (BEIS) and the Office of Gas and Electricity Markets (Ofgem) expectations set out in the agreed Terms of Reference (ToR)[3]. This requires us to identify the changes which are likely to be required to industry codes, standards, and licences in respect of the HND. Ofgem reaffirmed the requirement for us to develop this recommendation report, and other related outputs, in their Offshore Transmission Network Review (OTNR) related consultation[4] of July 2021.

These views are subject to subsequent decisions from Ofgem and further refinement as we continue to develop our own thinking and engage with impacted and interested stakeholders. In future when it comes to raising code and standard modifications via open governance, we will aim for pace and pragmatism where change is required to facilitate the HND recommendations.

The target audience for this recommendation report is industry stakeholders with an interest in code and standard change, including developers within the HND. If you would like a higher-level overview of the potential impacts on codes and standards, a summary of our key findings can be found in Section 2. Throughout this report we have posed key questions related to our initial views and welcome feedback on these, including any areas where stakeholders think we are yet to identify a potential code and standard impact associated with the HND. Further information about our planned next steps and future engagement can be found in Section 10. This report sets out:

- Initial views on code and standard impacts related to the preferred offshore delivery model
- Initial views on code and standard impacts related to the HND recommendations
- Initial views on a connection contract update programme as a result of the above impacts

Background

In July 2020 the Energy Minster launched the OTNR. The objective of the OTNR is "to ensure that the transmission connections for offshore wind generation are delivered in the most appropriate way, considering the increased ambition for offshore wind to achieve net zero. This is with a view to finding the appropriate balance between environmental, social and economic costs".

[1] www.ofgem.gov.uk/publications/offshore-coordination-early-opportunities-consultation-our-minded-decision-anticipatory-investment-and-implementation-policy-changes
[2] www.ofgem.gov.uk/publications/minded-decision-and-further-consultation-pathway-2030
[3] https://www.gov.uk/government/groups/offshore-transmission-network-review
[4] www.ofgem.gov.uk/publications/consultation-changes-intended-bring-about-greater-coordination-development-offshore-energy-networks

The OTNR is led by BEIS with support from a range of UK Government and industry bodies. We and several other organisations are project partners. More information on the OTNR and the project partners can be found on BEIS's website[5].

In November 2020 the UK Government published its Ten Point Plan for a Green Industrial Revolution[6], which makes clear that offshore wind is a critical source of renewable energy for the UK's growing economy. In this plan the UK Government expressed its ambition to quadruple its offshore wind capacity by 2030 to 40 GW and achieve net zero greenhouse gas emissions by 2050. In the British Energy Security Strategy (BESS)[7], published April 2022, the UK Government increased its ambition for offshore wind to 50 GW by 2030. Alongside this the Scottish Government has an ambition for 11 GW offshore wind by 2030 and net zero greenhouse gas emissions by 2045.

To help realise these targets, a step change in both the speed and scale of deployment of offshore wind is required. The onshore and offshore transmission networks play a crucial role in making this happen. They need to change and grow in a way that is efficient for consumers and considers impacts on communities and the environment. Since the beginning of the OTNR, we have been playing a key role in actively assessing whether there is a better approach to offshore networks. We are committed to delivering better outcomes for consumers and communities and supporting delivery of the UK Government's net zero ambitions.

In December 2020 we concluded there is significant benefit to coordination

In December 2020 we published a report[8] on the costs and benefits of a more coordinated approach to connecting offshore wind and interconnectors compared to the current radial connection approach. With a radial approach, windfarms have individual connections to the main transmission network. These individual connections are designed independently from the onshore network which transports electricity around the country. We confirmed there is significant benefit in moving quickly to an integrated network in which the onshore and offshore networks are coordinated to optimise the investment across the two and balance the design objectives. The analysis also suggested it is important to consider what flexibility there is for coordination between 2025 and 2030.

The HND is delivered in consultation with the Central Design Group (CDG) and governed by a ToR

Following the December 2020 publication, BEIS and Ofgem requested that we deliver the HND, in consultation with the CDG. This group was set up in 2021, to establish and support our development of the HND and to ensure stakeholder views were considered in the design. The purpose of the CDG is to act as a vehicle for us to consult and collaborate with Transmission Owners (TOs) on the HND, and to consult with stakeholder groups as the HND is developed. The CDG is chaired by the Electricity System Operator (ESO) with the TOs and ESO as members. BEIS, Ofgem and the Scottish and Welsh Governments are observers.

The specific roles for developing the HND by the ESO, CDG and its CDG subgroups are explained in the *HND Methodology*[9], which was published in February 2022, and the HND ToR[10].

The ToR ask us to deliver an HND that considers the onshore and offshore network required to connect offshore wind. This is in order to connect offshore wind to facilitate the pace and certainty required to deliver the 2030 offshore wind ambitions, and the 2045 and 2050 net zero targets. The ToR requires the HND to be economic and efficient, deliverable, and operable, and minimise the impact on the environment and local communities.

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[5] www.gov.uk/government/groups/offshore-transmission-network-review#terms-of-reference
[6] https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/936567/10_POINT_PLAN_BOOKLET.pdf
[7] www.gov.uk/government/publications/british-energy-security-strategy
[8] www.nationalgrideso.com/document/183031/download
[9] www.nationalgrideso.com/document/239466/download
[10] https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/1059676/otnr-central-design-group-network-design-tor.pdf

2 Key findings

Our key findings to date for further consideration and engagement are:

2.1 Offshore delivery model

Ofgem's offshore delivery model minded-to decision[11] to deliver the Holistic Network Design (HND) introduces the concept of generators undertaking detailed network design, consenting, and construction of offshore transmission infrastructure for their project, other projects and wider system reasons. In addition, the offshore delivery model could introduce the concept of a coordinated Offshore Transmission Owner (OFTO) depending on the structure of the offshore transmission system.

Generator commissioning clause

Under current legislation a generator is permitted to transmit electricity for up to 18-months between energisation of the offshore transmission system and the appointment of an OFTO. During this time the offshore transmission system remains under generator ownership, and it is not classified as part of the National Electricity Transmission System (NETS). This introduces potential complexities with any subsequent generator(s) connecting within this 18-month period. Therefore, appropriate arrangements need to be identified and developed to facilitate the connection of any subsequent generation within this 18-month period.

OFTO licence

A more coordinated offshore transmission system may expand incrementally over time. This presents a potential complexity that arises from a standard OFTO licence. Within a standard OFTO licence, there is currently a 20 per cent cap on additional investment that can be made by an OFTO to facilitate new connections. Therefore, a licence change could be required to facilitate additional investment if it is deemed the most economic and efficient way to facilitate new connections, or to address wider system issues. Therefore, in line with their minded-to decision consultation, we anticipate that further consideration is required by Ofgem on if and how such a standard licence condition change could be made in future.

System Operator Transmission Owner Code (STC)

It is likely that the STC needs to be amended to introduce the concept of a coordinated OFTO and an offshore transmission interface site as a result of the offshore delivery model minded-to decision. This will trigger a requirement for the introduction of new associated STC-derived agreements, such as an offshore transmission interface agreement. The latter point could lead to a subsequent need to extend STC Section K provisions to provide additional clarity on the technical requirements at an offshore transmission interface site. The STC changes related to the HND recommendations are summarised in Section 2.5.

Connection and Use of System Code (CUSC)

The CUSC changes arising from the offshore delivery model minded-to decision are expected to be minimal. There are CUSC changes related to the HND recommendations on network charging, user commitment and queue management which are summarised in Sections 2.6, 2.8 and 2.9. The other potential CUSC changes relate primarily to the definitions associated with the offshore transmission system. For example, it is likely that the concept of Offshore Transmission System Development User Works (OTSDUW) will need to be redefined to allow any works a primary generator is undertaking for subsequent generation or wider system reasons, to be differentiated from any traditional OTSDUW.

Grid Code

We have not identified any material changes required to the Grid Code as a result of the offshore delivery model minded-to decision. Minor changes could allow the HND to be delivered effectively under the generator build arrangements set out within the code. This assumes that relevant studies would be undertaken from the outset and that the offshore transmission system delivered by the primary generator would be delivered to the necessary standards to enable the connection of any subsequent generator(s) within the HND. The Grid Code changes related to the HND recommendations are summarised in Section 2.4.

[11] www.ofgem.gov.uk/publications/minded-decision-and-further-consultation-pathway-2030

2.2 Offshore transmission versus onshore transmission

It will be important that the network components within the HND can be formally classified as either offshore or onshore transmission. This will be an important distinction as there may be a different impact on codes, standards and/or connection contracts depending on whether a particular network component is considered to be offshore or onshore transmission. It will also be important to be able to distinguish between the radial and non-radial offshore transmission.

2.3 Security and Quality of Supply Standard (SQSS) recommendations

The SQSS defines a Direct Current (DC) bipole configuration as a single DC converter. Therefore, it is necessary to revise the SQSS to incorporate the HND recommendations. This depends on there being no common modes of failure that would affect the entire link, and that the loss is limited to a single pole at any point in time.

There continues to be value in the planned review of the loss of infeed risk criteria applicable to offshore DC converters to maximise the opportunity for optimising offshore network designs and to minimise the environmental impacts of such designs.

The SQSS currently specifies that an offshore transmission system extends from an offshore grid entry point to one transmission interface point. To allow for multiple interface points, it will be necessary to introduce some minor, mostly topographical modifications to SQSS Section 7, and to update the narratives in SQSS Section 1. Such changes are unlikely to be substantial.

We have already consulted on and published a plan[12] to review the SQSS over the RIIO-2 period and will prioritise addressing issues that could act as a blocker to the HND recommendations, including those highlighted above. There will be a further review to address any other remaining issues.

2.4 Grid Code recommendations

Grid Code changes as a result of the HND recommendations will require further consideration. The Grid Code already contains offshore provisions related to generator build arrangements (i.e., related to OTSDUW and the requirements at a grid entry point offshore, etc) which remain applicable to allow the HND to be effectively delivered with the minor changes summarised in Section 2.1.

There will need to be further consideration of the generic requirements for reactive capability in the context of the HND recommendations. A greater level of paralleling between the onshore and the offshore system will mean greater variability of the flows on offshore circuits. This may require that the offshore wind generator provides a wider reactive capability range to ensure that voltages on the offshore system could be managed within applicable limits.

The Grid Code also needs to allow the offshore transmission system to be developed in a modular way. Each offshore transmission section could be built by different developers so an electrical standard[13], as referenced in the Grid Code (such as ECC.6.2.1.2), will need to ensure appropriate standards exists. This will be required for the new coordinated offshore transmission system if different sections are subsequently interconnected.

Whilst this would cover the interface arrangements between connecting parties, each developer would need to make sure their offshore section is designed to the applicable SQSS, Grid Code and STC requirements.

Future offshore network designs are likely to drive further Grid Code changes, due to the introduction of new technology and design variants, and/or changes to offshore ownership boundaries.

2.5 STC Section K recommendations

Further to Section 2.1, it is anticipated that there will be minimal change required to STC Section K as a result of the HND, though any changes in the Grid Code would need to be reflected in STC Section K.

We think it is unlikely that other technical areas of the STC will be impacted by the HND, other than some additional consequential details that may be required in the STC Procedures.

[12] www.nationalgrideso.com/calendar/nets-sqss-review
[13] www.nationalgrideso.com/industry-information/codes/grid-code/electrical-standards-documents

2.6 Network charging

The network configurations within the HND were not originally envisaged when the offshore charging methodology was developed. Therefore, further to Section 2.1, the following challenges and associated methodology changes for Transmission Network Use of System (TNUoS) charges in CUSC Section 14 will need to be considered to facilitate the HND. We do not expect there to be any changes required in relation to Balancing Services Use of System charges or connection charges.

Allocating charges between offshore generators who are utilising the same offshore assets is not explicitly outlined in the CUSC. This will require a methodology change, which can be split into two topics - determining which offshore substations and circuits an offshore generator should pay towards and the method used to apportion costs between two or more generators utilising the same offshore circuit and offshore substation. Additionally, there will be a need to determine which offshore assets are classed as pre-existing assets for each developer in line with the CUSC.

Some methodology clarity is also needed to determine the appropriate wider tariffs when an offshore generator can be connected to two or more onshore Main Integrated Transmission System (MITS) Nodes which fall into different generation zones.

There is also the potential for onshore generators to utilise the offshore network to move energy to different points on the onshore network, assuming the offshore network is operated in an integrated configuration. Consideration should be given to charge relevant onshore generators to reflect their usage of the offshore circuit in such circumstances.

There could be benefit from the introduction of an offshore MITS Node definition if there is to be MITS offshore, as could be the case due to the HND. Potentially, there will need to be a distinction made between MITS Node definitions onshore and offshore. There would need to be consideration of the charges for relevant offshore assets due to the existence and definition of an offshore MITS Node. Onshore generators directly connected to a MITS Node are not liable for local tariffs and this may not be the best approach for an offshore MITS Node.

There are questions related to the Anticipatory Investment (AI) Cost Gap outlined in Ofgem's Early Opportunities minded-to decision on AI[14]. Subject to the final decision from Ofgem, the principle of how the AI Cost Gap is paid by the subsequent generator needs to be outlined in the CUSC.

A generator build delivery model and the generator commissioning clause need further consideration. If a subsequent generation connects during the 18-month period utilising the primary generator's assets there may need to be an arrangement and a methodology in place for the subsequent generator(s) to pay the primary generator for utilising those assets.

At present, some elements only reflect the characteristics of the onshore network with the wider tariff. One element is the 'connectivity' between zones that the TNUoS model uses to reflect how the zones are connected. However, with the HND there is the potential for energy to 'jump' between zones being transported via an offshore circuit and not via onshore zones.

2.7 Access rights

Certain elements of the HND will remain the same or similar to existing offshore arrangements. For example:

- The HND will be built to SQSS Section 7.
- No offshore outage condition ('N-1') will curtail a generator to below 50 per cent of their capacity.
- No compensation will be payable for N-1 outages.

Further analysis and engagement is required on whether established queue-based principles, where an earlier contract start date could mean fewer enduring restrictions, are still relevant in respect of access rights on non-radial offshore transmission. It may be that more equitable curtailment for each component of the offshore transmission system design is more appropriate. For example, if a shared offshore system loses 50 per cent of its capacity to transfer power, each generator in that regional network could potentially be curtailed down to 50 per cent rather than allowing the generator with the earliest contract signature date to have greater access than any other generator(s) connected to that non-radial offshore transmission system.

[14] www.ofgem.gov.uk/publications/offshore-coordination-early-opportunities-consultation-our-minded-decision-anticipatory-investment-and-implementation-policy-changes

2.8 User Commitment (UC)

Further to Section 2.1, a code change is likely to be required in relation to UC. It will be separate to but cognisant of CMP385[15]. It is likely that AI as a concept will need to be defined and added into CUSC Section 15 and that UC arrangements will need to extend to OTSDUW under generator build arrangements.

The extent to which UC arrangements are extended will depend on policy decisions from Ofgem and further industry engagement in relation to the HND. Key considerations will be whether UC offshore only applies to the subsequent generator(s) and only in relation to AI, as per Ofgem's minded-to decision related to Early Opportunities workstream[16], or whether both the primary generator and the subsequent generator(s) have UC liabilities and security requirements.

If the decision is to apply the Early Opportunities principles to the HND, clarity will still be required on how AI is to be secured by the subsequent generator(s). For example, whether AI liability is secured in full by the subsequent generator(s), or whether there is a sharing mechanism with consumers through existing or updated UC factors, such as the Strategic Investment Factor.

2.9 Queue management

Further to Section 2.1, queue management considerations in relation to the HND will be incorporated into a CUSC modification that will progress the broader connection Queue Management principles under CMP376[17]. All CMP376 principles are expected to apply to the HND projects.

These projects will likely have HND-specific queue management provisions to be adhered to, such as to reflect any requirements of the preferred offshore delivery model. The scope will be further developed during the progression of the modification. Stakeholders will be able to share views during our engagement prior to the modification starting and throughout the modification process. The key themes of the HND and offshore delivery model-specific additions will likely focus on the following areas:

- An exemption from the queue management impact in certain instances where a programme delay is caused by another generator. For example, where AI being delivered by a primary generator is delayed and results in a delay to the programme of the secondary generator(s) dependent upon that AI, an exemption could then potentially apply to the secondary generator(s).
- The relationship between the OTSDUW of the primary generator and its own generation asset works i.e., to what extent (if at all) does a delay to the OTSDUW exempt the primary generator for any consequential delay to their generation asset programme.
- The relationship between two or more parties which are interdependent on each other's programmes due to the preferred offshore delivery model and any exemptions or non-exemptions from delay impacts.

The extent to which these issues are relevant will be determined once the sequencing of the HND works is known and attributed to TOs and developers. It is expected that due to queue management principles, generators may have the ability to connect earlier than first anticipated due to the re-positioning or termination of delayed generators, if and where queue management arrangements have been implemented. Any earlier connection will also depend on the specific network circumstances in the vicinity of the connection.

2.10 Connection contract update programme

The HND recommendations and the Ofgem minded-to decision[18] on offshore delivery models need to be brought together and translated into connection contract updates for in scope developers[19]. In scope developers will then need clarity on, amongst other things, the works to be delivered by each party, and the works each party is dependent upon prior to their connection, alongside the delivery date of those works.

In addition, there are risks and uncertainties which need to be managed via the connection contracts.

[15] This code modification is seeking to improve current user commitment arrangements and further information can be found as follows. www.nationalgrideso.com/industry-information/codes/connection-and-use-system-code-cusc-old/modifications/cmp385
[16] www.ofgem.gov.uk/publications/offshore-coordination-early-opportunities-consultation-our-minded-decision-anticipatory-investment-and-implementation-policy-changes
[17] This code modification is seeking to introduce queue management principles and further information can be found as follows. www.nationalgrideso.com/industry-information/codes/connection-and-use-system-code-cusc-old/modifications/cmp376-inclusion
[18] www.ofgem.gov.uk/publications/minded-decision-and-further-consultation-pathway-2030
[19] The connection contract update programme will also need to consider any potential consequential connection contract impacts for developers which are not included within the HND.

We are currently working on a connection contract update programme with the aim to provide updated connection contracts to in scope developers in Autumn 2022, and to commence tripartite discussions with those developers and the Transmission Owners in Summer 2022. These timescales are subject to further clarity being provided on certain pre-requisites, such as which party is to deliver which component of the offshore transmission system, etc. As these timescales are subject to further clarity being provided this may result in connection contract updates extending beyond Autumn 2022.

We will work with Ofgem and developers in respect of any coordinated offshore transmission system within the HND recommendations, to agree how it can be delivered so that connection contracts can be updated as soon as practicable.

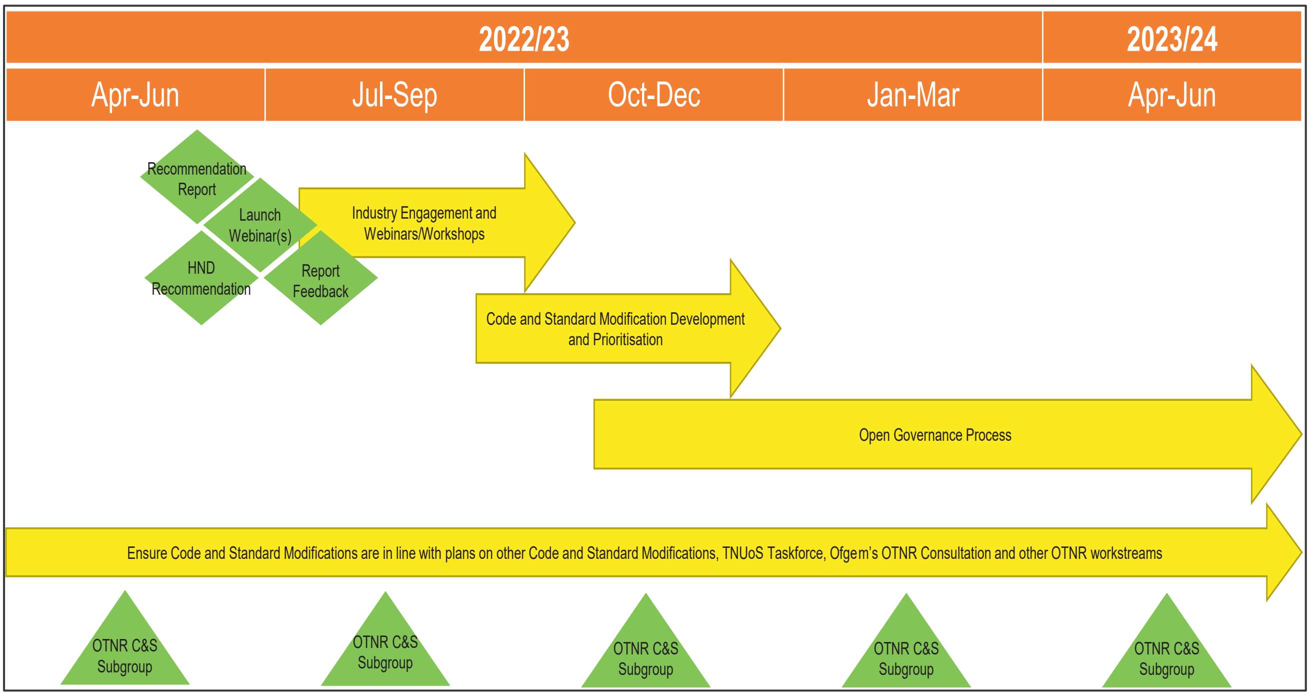
The exception to these timescales relates to in scope developers within the Celtic Sea. Due to the HND recommendations for the region, we no longer plan to update these connection contracts until after the conclusion of the HND follow up process and/or once leases for the region have been awarded.

As we have previously communicated, we also plan to terminate connection contracts with unsuccessful ScotWind developers at an appropriate time.

2.11 Conclusions and next steps

There are many remaining uncertainties related to the design and preferred offshore delivery model in the context of codes and standards. Our initial analysis summarised above has resulted in our current views about potential matters to resolve in the codes and standards as a result of the HND recommendations and Ofgem's minded to decision on offshore delivery models. We recommend a period of further analysis and stakeholder engagement prior to formal code and standard modifications. We welcome feedback on the content of this report, especially where we have prompted it throughout, and are planning to engage further with industry stakeholders throughout Summer 2022 with the aim of formally raising any necessary code and standard modifications in Autumn 2022. If there is a case to formally raise a modification in quicker timescales this will be considered, and if a modification is less urgent or less important it could be delayed until a more suitable time. We will work with stakeholders on when code and standard change is necessary and the content of the code and standard change. This will include engagement through the Expert Advisory Group Codes and Standards subgroup.

Further information on our plans for our code and standard modification programme engagement throughout Summer 2022 will be made available in July 2022. An initial webinar to talk through and discuss the content of this report is to be scheduled for Tuesday 19 July and further information on this webinar will be available in the near future. An overview of the next steps is as follows.



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3 Early Opportunities overview

This section provides information on the relevant areas of the previous and ongoing work within the Early Opportunities workstream. It highlights where there may be relevant links to the Pathway to 2030 workstream in respect of potential changes to codes and standards.

3.1 Workstream objective

The objective of the Early Opportunities workstream is to capitalise on early opportunities for coordination through identifying inflight projects that have the potential to coordinate with changes to, or existing flexibility within, the current regulatory framework. Early Opportunities is developer-led so developers of relatively advanced offshore wind projects are encouraged to propose and deliver coordinated solutions by opting into coordination. BEIS and Ofgem have defined the scope as projects with the opportunity for early coordination, whilst mitigating disruption to their contribution to the 2030 ambitions. These projects are:

1. **Without fully approved planning permission**

   Planning permission, granted by the relevant authority, to undertake a major infrastructure development such as building and connecting a wind farm.

2. **Been assessed through the Connections and Infrastructure Options Note (CION) process[20]**

   Our CION process provides the rationale for selecting the most economic and efficient connection option from the assessment of technical, commercial, regulatory, environmental, planning and deliverability aspects.

These projects generally have a connection contract with a connection date in or before 2030 and in the main are located off the east coast of England.

The Early Opportunities workstream commenced industry work on the impact of offshore coordination on codes and standards and is considering whether there is sufficient flexibility within the current regulatory framework to allow for coordination of inflight projects. We are identifying codes, standards and relevant process changes that may be needed to enable those coordination opportunities and progressing those changes as relevant. There is a need for a balance between maintaining the pace of delivery required to meet the Government's ambition for 50 GW offshore wind by 2030 and capitalising on early opportunities for coordination to maximise the social, economic, and environmental benefits.

3.2 Concepts

Ofgem has previously outlined the different Early Opportunities concepts. Each concept has unique risks and barriers to overcome; grouping them has allowed us to assess the feasibility and impact of each concept individually. Each concept can be found in a previous Ofgem consultation[21] on Early Opportunities, Pathway to 2030 and Multi-Purpose Interconnectors. We used these concepts to start our early thinking on potential code and standard impacts related to the Pathway to 2030 workstream prior to the Holistic Network Design (HND) options and recommendations being available. Once we had more information about the HND options and recommendations we started to consider those in place of these Early Opportunities concepts.

3.3 Offshore delivery model

Unlike the Pathway to 2030 workstream, the Early Opportunities workstream is largely expecting to operate within the existing frameworks. This is likely to mean using the generator build delivery model, as used predominantly today for offshore wind connections. Under this offshore delivery model, the generator designs and builds the offshore infrastructure for the connection of offshore wind and is responsible for those assets until a future transfer to an Offshore Transmission Owner (OFTO). Opt-in developers would voluntarily coordinate between themselves to understand and adapt arrangements within the status quo offshore delivery model that would be taken forward to progress their coordinated design. An OFTO build model is an option, but not generally preferred by generators and may be impracticable given the timescales. This supported our early thinking for the Pathway to 2030 workstream.

[20] www.nationalgrideso.com/document/45791/download
[21] www.ofgem.gov.uk/publications/consultation-changes-intended-bring-about-greater-coordination-development-offshore-energy-networks

3.4 Progress to date

In analysing the viability of the Early Opportunity concepts, we considered the impact of those proposals on various codes and standards.

- System Operator Transmission Owner Code (STC).
- Security and Quality of Supply Standard (SQSS) and Grid Code.
- Connection and Use of System Code (CUSC).

There are many existing code modifications, wider considerations (such as the TNUoS Taskforce), and other OTNR workstreams that will have interactions with the Early Opportunity project proposals. This will require coordination between the relevant parties to ensure a successful outcome. As the interactions will have various timescales associated with them, code modifications raised under this workstream will need to be continually reviewed and updated accordingly.

It has been highlighted previously that codes and standards are a key risk to developers in progressing coordinated proposals. We have created and are leading the Offshore Transmission Network Review (OTNR) Expert Advisory Group (EAG) Codes and Standards subgroup to provide transparency and visibility in the programme management of changes needed to codes and standards across the OTNR, including those needed within Pathway to 2030. The subgroup meets monthly, and any developer can attend. It aims to provide an opportunity to raise questions and awareness of the changes to codes and standards that will enable offshore coordination. Information on how to join the distribution list for updates relating to this can be found on our website[22].

Our work on codes and standards for the Early Opportunities workstream formed the baseline for our thinking in respect of the Pathway to 2030 workstream. We next summarise our findings from the Early Opportunities workstream, including noting where those findings are also relevant to findings presented in the subsequent Pathway to 2030 sections of this recommendation report.

3.5 STC

The existing regulatory framework and licencing regime remains unchanged in respect of Early Opportunities. In our view, it is not necessary to raise any changes to the STC at this point in respect of Early Opportunities. To support this, the Early Opportunity proposals put forward by developers to date have not identified any change is required to the STC.

3.6 SQSS and Grid Code

Having collaborated with the Early Opportunity opt-in developers on understanding their proposals to date, it has been established that one change to the SQSS will be required in respect of Early Opportunities.

No amendment to the Grid Code has been identified in respect of Early Opportunities.

The change to the SQSS which has been identified relates to the need to increase the normal/infrequent infeed risk from 1320 MW to 1800 MW and to facilitate future expansion of OFTO networks. This proposed change requires further development as it addresses wider questions such as the 1800 MW infeed loss risk, the optimum sizing of the offshore network and how to operate in a low wind situation.

This is also relevant to the HND and has been further explored in Section 6.

3.7 CUSC

From the gaps we have identified in relation to the Early Opportunities concepts, we are currently proposing the following three code modifications under the Early Opportunities workstream. There are other identified gaps and challenges to the charging methodology that may require a change to the codes and standards. They are not needed at this stage for Early Opportunities proposals, and it is our view that these three proposed code modifications are prioritised for Early Opportunities.

3.8 Recommended code modifications

These three code modifications have been identified in relation to Early Opportunities. They are summarised below, and all are relevant to Pathway to 2030 so are further explored in the context of the HND in Section 7.

[22] www.nationalgrideso.com/future-energy/projects/offshore-coordination-project/latest-news

The allocation of charges between two or more users when sharing the same local offshore circuits and offshore substation, under the charging methodology.

Local offshore circuit and substation tariffs form part of the calculation of the offshore generation tariff. In the charging methodology, calculation of the offshore tariffs does not accommodate offshore assets that are shared between multiple generation users.

Clarity of which wider tariff is applied, when a user is connecting to two or more onshore MITS Nodes that are in different generation zones, under the charging methodology.

The wider tariff is one of the components that forms the TNUoS charge. The wider tariffs are a £/kW tariff that differs between each of the 27 generation zones. If a generator is connecting to two or more different generation zones, clarity is needed on how the wider tariff is applied.

Any changes required to accommodate the connection of different developers who are connecting at different times, under a generator build option.

Following a cost assessment process between Ofgem and the developer, the Allowed Revenue is used to calculate the TNUoS charging for offshore generators. The primary generator builds offshore transmission system to facilitate the connection of subsequent generation where the subsequent generation is connecting later than the primary generation. We assume that the cost of building the required offshore transmission system for both the primary and subsequent generators is approved as Allowed Revenue. Prior to the subsequent generator(s) being connected, the Allowed Revenue is recovered via either the TNUoS charges made by the primary generator or via the demand residual. This principle is to be discussed with stakeholders as to whether this remains a suitable arrangement, in accordance with Ofgem's minded-to decision and consultation related to Early Opportunities.

3.9 CUSC User Commitment methodology

As the developers under Early Opportunities tend to adopt the generator build option, this means that for any coordination proposal there will be a primary developer building offshore assets for one or more other developers. As a result, developers require an understanding of how User Commitment will be managed under this scenario. This is further explored in the context of the HND in Section 8.3.

3.10 Next steps and minded-to decisions

We will work with stakeholders to discuss and progress the scope of the proposed code modifications and continue our engagement via established industry groups. The OTNR EAG Codes and Standards subgroup will be held monthly to programme manage codes and standard changes for all the OTNR workstreams. It is hoped that this early engagement will assist industry in understanding the recommended code modifications and may lead to concise discussions in the governance process.

On 14 April 2022, Ofgem published their minded-to decision in relation to Anticipatory Investment in the context of the Early Opportunities workstream. There is a question as to the extent which some of these minded-to positions related to Early Opportunities will be relevant to the HND and this requires consideration. Our interpretation of some of the key elements of this minded-to decision are summarised as follows:

- For 'known projects' (i.e., any 'projects with an…Agreement for Lease…and have been through the CION process') Generator Focused Anticipatory Investment (GFAI) becomes possible. This GFAI will be considered and permitted by Ofgem through some form of early assessment process.
- This early assessment process will identify a GFAI Cost Gap Risk. Consumers will pick up the GFAI Cost Gap risk until a second generator starts paying TNUoS. This cost risk will partially be offset by the second generator picking up and securing User Commitment (UC) liability in case they do not connect. The amount they are liable for could be less than the GFAI Cost Gap risk value due to some consumer sharing via UC arrangements. The way this would occur remains to be confirmed via the content of a code modification in future. This is further considered in the context of the HND in Section 8.3.
- There would be no change to UC for the primary generator, who would continue to self-secure, or for the second generator in respect of 'non-AI' i.e., they would only be liable for and secure GFAI under UC arrangements. The second generator could also potentially self-secure any additional works being undertaken at a later date. If the second generator connects and starts to pay TNUoS from that date then the GFAI Cost Gap will be added to their TNUoS charges but the way this would occur remains to be confirmed via the content of a code modification in future. This is further considered in the context of the HND in Section 7.10.

4 Offshore delivery model overview

4.1 Introduction

Ofgem's proposed offshore delivery model for non-radial solutions within the Holistic Network Design (HND), as set out in their May 2022 minded-to decision[23] (very late-competition generator build), introduces the potential for multi-generator coordination, and in turn the concept of primary and subsequent generators. This section explores the potential code, standard and licence implications of the preferred offshore delivery model for non-radial offshore transmission in the context of the HND recommendations.

Under this very late-competition generator build offshore delivery model, subsequent generators may be subject to the successful delivery of the primary generator's project and its associated timescales for delivery to enable their connection to the offshore transmission system. This is due to the fact that the primary generator would build and connect to the identified onshore interface point, including any necessary anticipatory investment/infrastructure, with subsequent generators thereafter connecting via an offshore substation built by the primary generator.

Ofgem has set out a proposed new tender entry condition under the Tender Regulations, intended to ensure non-radial offshore transmission assets are economic, efficient, and coordinated. As such, they propose to introduce a new developer-led mandatory gateway assessment process intended to provide developers with certainty that proposals will meet the requirements of the new tender entry condition. Ofgem intends to publish detailed guidance around this process and the requirements for developers in due course, and ahead of the new process coming into effect in future.

Additionally, Ofgem has set out criteria for what they would consider to be radial offshore transmission and what they would consider to be non-radial offshore transmission. Within the criteria, Ofgem also confirms that asset classification as either onshore transmission or offshore transmission would be determined by the asset's primary function electrically, rather than its spatial location. We intend to support Ofgem following the publication of the HND to determine asset classification for the recommended design within the HND.

Ofgem has also set out their decision relating to the delivery of any radial offshore transmission recommended within the HND. These projects will follow the current offshore arrangements, meaning that developers will have the choice of a generator build or Offshore Transmission Owner (OFTO) build process.

4.2 Generator commissioning clause

The Energy Act 2013 introduced section 6F[24] - known as the generator commissioning clause - which creates an exemption to the prohibition of offshore transmission activity during a commissioning period in certain circumstances. In broad terms, this permits offshore wind farm developers to transmit electricity over an offshore transmission system for up to 18 months from the issue of a completion notice, after which period, the transmission assets must be transferred to an OFTO.

As such, up until OFTO appointment and Offshore Transmission System User Asset (OTSUA) Transfer Time, any offshore transmission built by the primary generator remains under the developer's ownership, rather than being owned by an OFTO as part of the National Electricity Transmission System (NETS). If arrangements for any subsequent generator(s) to connect to the assets of the primary generator remain unclear this could cause issues for developers. This could be for a period of up to 18 months following the primary generator's energisation date in accordance with the generator commissioning clause timescales, unless it is extended.

When considering the above, it is currently unclear what rights and obligations would exist in respect of the primary generator and the subsequent generator(s) for connection of the subsequent generator(s) to offshore transmission owned and operated by a primary generator which is not part of the NETS. We have identified initial options to address the potential barrier described above and an overview of these are as follows:

- **Option 1**: Generators could potentially act in a joint venture capacity. For example, by taking a regional approach, with the associated contractual arrangements being agreed upon between those generators in advance. This could allow both the primary and subsequent generator(s) to connect to joint venture owned assets prior to OFTO appointment and OTSUA Transfer Time. The developers would both rely on the assets delivered by the joint venture rather than the subsequent developer(s) relying on assets delivered by the primary developer as would be the case without joint venture type arrangements.

[23] www.ofgem.gov.uk/publications/minded-decision-and-further-consultation-pathway-2030
[24] www.legislation.gov.uk/ukpga/2013/32/section/147/enacted

- **Option 2**: The ESO could potentially obligate the primary generator to allow connections by the subsequent generator(s), prior to OFTO appointment and OTSUA Transfer Time. This could be via a new contractual agreement between the primary and subsequent developer(s) as a condition of their connection contracts. We could produce a pro forma for the new agreement and associated clauses within connection contracts via the connection contract update programme detailed in Section 9. It is expected that this proforma agreement could replicate the fundamental rights and obligations related to connections, as they exist after the OTSUA Transfer Time. There could be potential for divergence due to any situation specific considerations. For example, the subsequent developer(s) damaging equipment owned by the primary developer. We would like to further explore the concept of a pro forma agreement with relevant developers as part of the connection contract update programme.
- **Option 3**: The ESO would not seek to formally obligate the primary generator to allow connections by the subsequent generator(s) prior to OFTO appointment and OTSUA Transfer Time as per Option 2 above. However, we would expect the relevant generators to reach some form of agreement between themselves and provide confirmation to us. We could make the connection contracts conditional upon such commercial agreement between developers. This option is similar to Option 1 above in that the developers would need to reach an agreement amongst themselves in relation to the relevant time period but without the formation of a joint venture.
- **Option 4**: The ESO could seek to enter into some form of arrangement with the primary generator to treat the offshore transmission system as the NETS for the period between offshore transmission system commissioning and the OTSUA Transfer Time. Alternatively, this could potentially be enacted via code changes. There could be potential for divergence due to different considerations existing for that period, as considered in Option 2 above.
- **Option 5**: If it is not possible to reach a satisfactory outcome under the above options, we could potentially be required to defer the connection date of any subsequent generator(s) until on or after the OFTO appointment and OTSUA Transfer Time. We have provisionally discounted this option as it is likely a non-viable option considering it does not provide for timely connections.

In respect of Options 2 and 3 there is a question on whether the subsequent generator(s) would require a different form of connection contract with us, such as a Bilateral Embedded Generation Agreement. This would be for the up to 18-month period where they are connected to an offshore transmission system owned by the primary generator which is not considered to be the NETS.

There could also be additional regulatory options which are available. For example, Ofgem requiring through the cost assessment process and/or licencing arrangements that the subsequent generator(s) be allowed to connect within the 18-month period where their connection date(s) so require.

Q1 Do you agree with our initial analysis of the generator commissioning clause challenge associated with the preferred offshore delivery model as above? Are there any other options? Please explain your rationale.

4.3 OFTO licence

The HND recommendations introduce the potential for the concept of coordinated OFTOs, which in turn presents a potential requirement to amend the standard OFTO licence. The introduction of such a concept into the System Operator Transmission Owner Code (STC) is further considered in Section 4.4.

Amended Standard Condition E12 - J4: Restriction of Transmission Revenue: Annual Revenue Adjustments – Part C Paragraph 20(a)(ii) sets out a 20 per cent cap on additional investment that can be made by an OFTO in relation to the facilitation of new connections. This 20 per cent cap is also referenced in Standard Licence Condition E17 Paragraph 5(d).

A coordinated OFTO could be required to incrementally increase the sections of the NETS under their ownership in future. There is the potential that the ceiling applied to additional investment via the 20 per cent cap could restrict the ability of an OFTO under licence to provide the necessary additional investment to facilitate new connections. This would occur even if it were deemed to be the most economic and efficient way to do so. This could also adversely interact with other network drivers, such as where work is identified through expanded network planning processes for coordinated OFTOs under the STC.

A licence change could be required to facilitate the additional investment that may be required. This could potentially be managed via different options. We anticipate that Ofgem may wish to further consider these options and others as follows.

- **Option 1**: The introduction of a targeted exemption to the 20 per cent cap specific to coordinated OFTOs, with set rules regarding applicability and clear guidance around what is to be considered as a coordinated OFTO and under which circumstances.
- **Option 2**: An uplift to the existing 20 per cent cap, with set rules regarding applicability and clear guidance around what is to be considered as a coordinated OFTO and under which circumstances.
- **Option 3**: The removal of the entire 20 per cent cap, with coordinated OFTOs being required to invest further if required under STC processes for connections and/or network planning purposes.

Q2 Do you agree with our initial analysis on a potential requirement to update the OFTO Licence due to the preferred offshore delivery model? Please explain your rationale.

4.4 STC

The provisions of the STC apply to transmission licensees and do not directly apply to generators, even in relation to generator build arrangements. In addition, current legislation prevents any one party from simultaneously holding both a transmission licence and a generation licence. Therefore, a generator cannot be classed as a transmission licensee, and as a result they are not bound by the STC. They are instead classified differently and are subject to the provisions of the Connection and Use of System Code (CUSC) and Grid Code by reference to the offshore system until the appointment of an OFTO.

We do not anticipate any changes to be required to the STC as a direct result of the offshore delivery model preferred by Ofgem.

However, as the HND introduces the potential for the concept of coordinated OFTOs we think there could be the potential for code changes related to this concept, coupled with the preferred offshore delivery model. The initial areas of the STC where we think there could be potential for changes, as well as the reason for why we think such change could be desirable, are as follows:

- The potential introduction of a coordinated OFTO as a concept within the STC. In future this could have similar obligations to a Competitively Appointed Transmission Owner onshore, including the obligations that are in place for TOs as set out in STC Section C: Transmission Services and Operations, and STC Section D: Planning Coordination in relation to network planning processes. However, this would require further consideration and engagement, including related to onshore network competition developments.
- The potential introduction of the concept of an offshore transmission interface site between OFTOs. This could result in concepts such as an offshore transmission interface site specification and an offshore site responsibility schedule, with a potential subsequent need to extend the relevant section to provide clarity on the technical requirements at the offshore transmission interface site. The relevant section would be STC Section K, which relates to the technical, design and operational criteria and performance requirements for offshore transmission systems.
- The potential need for the introduction of a STC Interim Section K Notification concept for OFTOs post the provision of a STC Final Section K Notification, in order to bring the OFTO back into compliance if required in respect of wider system requirements. Whilst this potential need requires further investigation, a potential solution could be akin to the Grid Code Limited Operational Notification process.

The STC is also briefly further considered in Section 6.4 in relation to the network design configurations that feature within the HND recommendations.

Q3 Do you agree with our initial analysis on a potential requirement to update the STC as a result of the preferred offshore delivery model as above? Please explain your rationale.

4.5 CUSC

Due to the introduction of a multi-generator dependency, with any subsequent generator(s) being reliant on the primary generator to build the shared offshore connection/interface point, there is a potential requirement to differentiate between categories of works within the CUSC. This is to reflect that there is potential for broader use assets and multiple connections.

More specifically, there may be a need to differentiate between works undertaken by the primary generator for the primary generator and works undertaken by the primary generator for the subsequent generator(s) and/or wider system reasons.

Clear classification of such works will help to enable the allocation of appropriate rights and obligations, including in relation to access provisions and charging arrangements. This will allow differentiation between the primary generator's works solely related to their own project and any works which are also for the benefit of others. Differentiation of works in this manner could be managed via minor adjustments to the definitions of Offshore Transmission System Development User Works (OTSDUW) and OTSUA, as well as any associated terms, and/or via updates to the connection contract arrangements between the ESO and relevant generators.

Subject to the approach taken to manage and enable the subsequent generator(s) to connect prior to OFTO appointment and OTSUA Transfer Time, it may also be necessary to codify a pro-forma contract related to the generator commissioning clause, as set out in one of the options in Section 4.2.

As a result of the network design configurations within the HND recommendations there are further potential changes to the CUSC. These include changes relating to Anticipatory Investment in the context of both Network Charging and User Commitment, as detailed in Section 7.10 and Section 8.3.

Q4 Do you agree with our initial analysis on a potential requirement to update the CUSC due to the preferred offshore delivery model as above? Please explain your rationale.

4.6 Grid Code

As a direct result of Ofgem's preferred offshore delivery model, our current view is that there would be minimal changes required to the Grid Code and that the HND could be delivered under the current generator build arrangements set out within the Grid Code.

The above view is contingent on the undertaking of the relevant studies from the outset to include any relevant provisions in connection contract technical appendices. It is also contingent on ensuring that, where required, the detailed network design stages consider and facilitate future connections by any subsequent generator(s). In this regard it will be paramount to ensure that the offshore transmission system built by the primary generator is built to the necessary standards to enable the connection of the subsequent generator(s), to in turn ensure that there are no retrospective changes required, unless that was originally planned.

For example, reactive power capabilities will need to be considered in the detailed network design stages for all generators connecting to an interlinked offshore transmission system from the outset rather than considering those incrementally as generators connect and offshore transmission system becomes available.

Whilst there are currently no material changes anticipated to be required to the Grid Code as a result of the preferred offshore delivery model, there may be administrative changes. For example, to ensure that what is to be considered as OTSDUW for the primary generator is clearly distinguished from OTSDUW that is being undertaken by the primary generator for other reasons, similar to the changes potentially required to the CUSC as per Section 4.5.

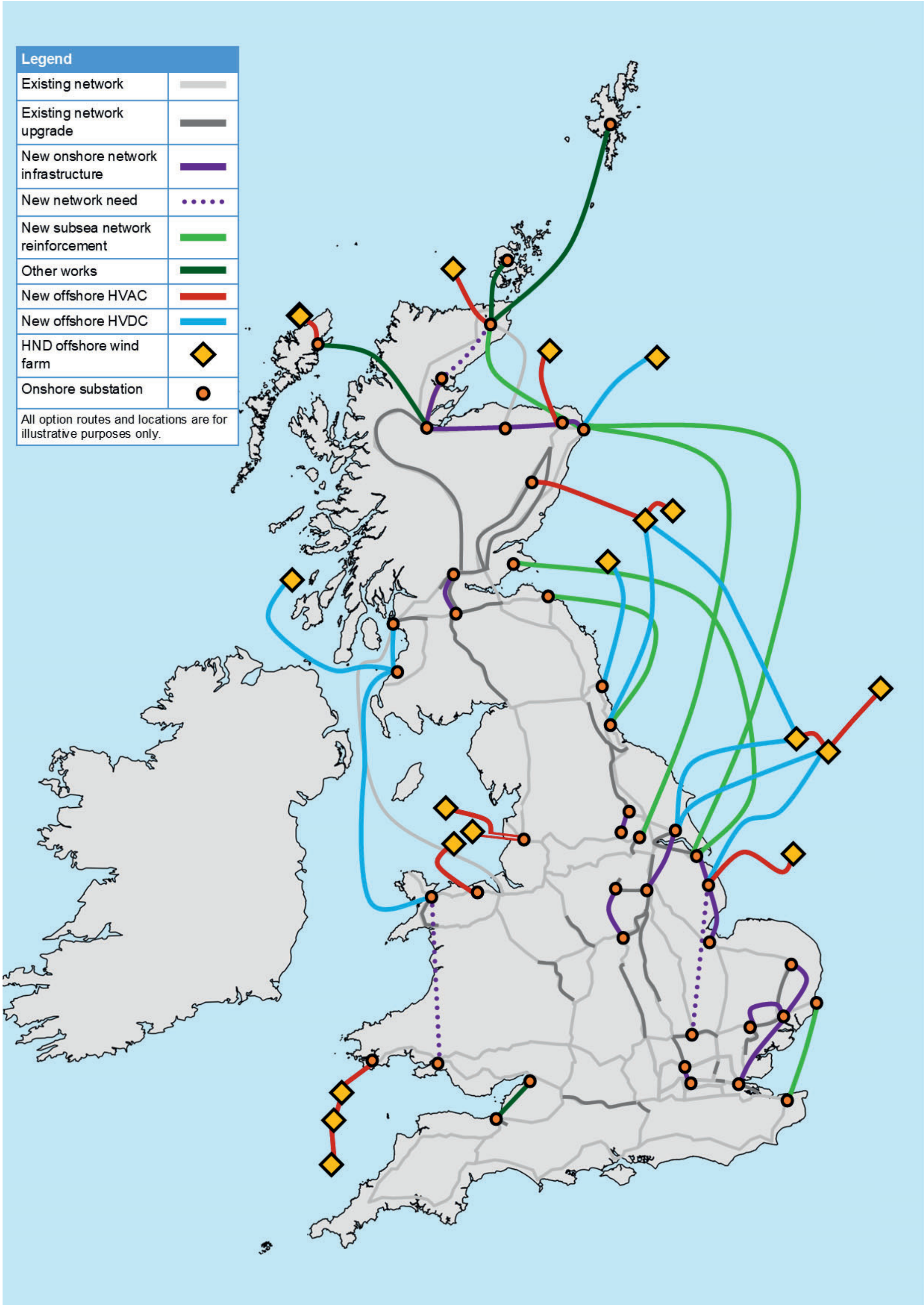
The Grid Code is also further considered in Section 6.3 in relation to the network design configurations that feature within the HND recommendations.

Q5 Do you agree with our initial analysis that there are no material changes to Grid Code associated with the preferred offshore delivery model as above? Please explain your rationale.

5 Holistic Network Design overview

This section explores the outcome of the Holistic Network Design (HND). The map in Figure 1 shows the HND recommendations. For further detail on how the HND was developed, please refer to our *HND Report*.

Figure 1: Map of HND recommendations



HND recommendations and overview

As part of developing the HND, network design rules[25] were agreed by the Central Design Group for use. These are as follows:

- For High Voltage Alternating Current (HVAC) or High Voltage Direct Current (HVDC) offshore systems, the infrequent infeed loss limit will be 1800 MW rather than the normal infeed loss limit of 1320 MW.
- The loss of infeed risk associated with any single circuit outage (AC or DC) will be capped to 50 per cent of the capacity of affected wind farms.
- An HVDC symmetrical monopole will have a capacity limit of up to 1800 MW[26].
- An HVDC bipole will have a capacity limit of up to 2000 MW. Each pole will also be considered as a separate circuit and have sufficient separation to avoid common mode faults. This includes cable separation and provision of metallic returns[27].
- HVDC circuit breaker technology will not be ready for when the design is being delivered.
- All HVDC systems will be automated such that flows can be redirected during fault conditions.

The details of what high-level designs have been recommended have been split into four regions to understand exactly how the developers are going to connect to the network in that region. These can be seen throughout the remainder of this section, including an overview of how the offshore substations were designed. Please note that routes shown on the diagrams do not represent the number of cables that will be used to provide the capacities needed across circuits. The regional designs will require a set of onshore works to facilitate the offshore network which is not shown in these figures.

This detail can be found in our *HND Report* and our *Network Options Assessment 2021/22 Refresh Report*.

It will be important that the network components within the HND can be formally classified as either offshore transmission or onshore transmission. This will be an important distinction as there may be a different impact on codes, standards and/or connection contracts, depending on whether a particular network component is considered to be offshore transmission or onshore transmission. This will be required when any non-radial offshore transmission assets within the HND recommendations are identified. We will work with Ofgem and developers to support the classification of the assets within the HND recommendations.

5.1 North Scotland Region

The region shown in Figure 2 shows both the ScotWind projects SW_N1 and SW_N4 connecting through a radial design with two AC circuits to Spittal and Arnish respectively. Due to the size of SW_N1, a full double busbar substation may be needed offshore to allow for a switch fault to prevent the loss of the whole wind farm, which would not be in line with standards.

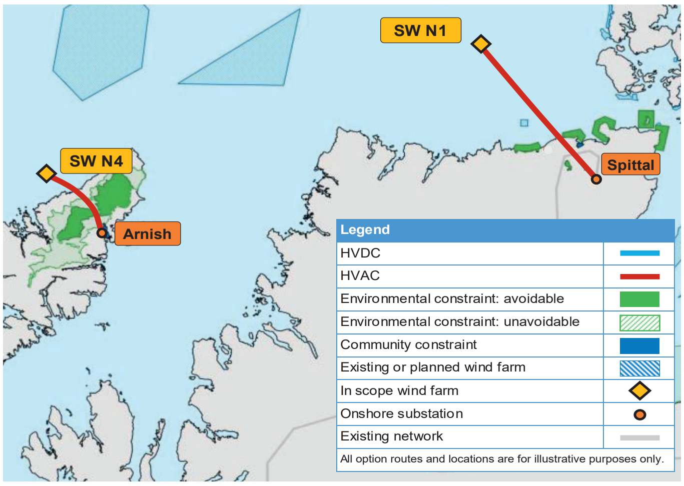


Figure 2: Recommended North Scotland Region

[25] Further information can be found in our *HND Report* - download (nationalgrideso.com)
[26] These limits have been referenced in the ESO Phase 1 Report - www.nationalgrideso.com/document/182931/download
[27] These limits have been referenced in the ESO Phase 1 Report - www.nationalgrideso.com/document/182931/download

5.2 North West Region

The region shown in Figure 3 shows how the wind farms are connected in the Irish Sea, including a ScotWind project in west Scotland.

The R4_4 (1500 MW) design connects to Bodelwyddan with a radial design through two AC circuits.

The R4_6 (1500 MW) and R4_5 (480 MW) designs connect through a shared cable corridor but electrically separate into Penwortham substation, as two radial connections.

The SW_W1 (2000 MW) design connects through a link to Pentir with a bootstrap connected to Hunterston via a new Tee-point. The link is a 2000 MW bipole with a metallic return, which means there are two electrical circuits of 1000 MW. As there are no HVDC circuit breakers, a fault on any of the three ends would result in the circuit being tripped. There are isolators at the Tee-point switching compound to allow the remaining circuits to be re-energised. This can be a slow procedure.

Beyond the switching compound at the new Tee-point, there is a question on if the circuit between this point and Pentir is classified as onshore or offshore transmission. This is further considered in the *HND Report*.

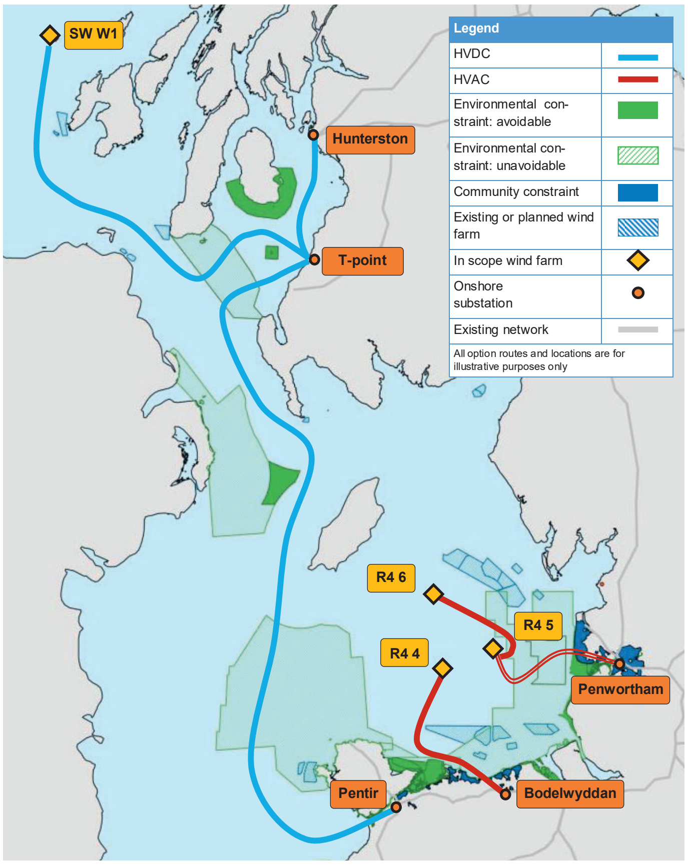


Figure 3: Recommended North West Region Design

5.3 East Coast Region

The East Coast Region covers Scotland and England due to coordination between Scottish and English wind farms.

The region shown in Figure 4 shows SW_NE4 (1500 MW), SW_NE7 (1500 MW), PA_2 (1800 MW) and R4_3 (1500 MW) wind farms connecting radially to onshore interface points i.e., New Deer, Peterhead, Blyth and Lincolnshire Connection Node substations. These are either AC or DC links to the onshore interface with 50 per cent redundancy, as per current standards.

SW_E1b (1200 MW) and PA_1 (1320 MW) connect radially through two AC circuits each to their respective offshore platforms.

SW_E1a (1500 MW) connects radially to Fetteresso substation via two AC circuits at 1000 MW each and to Hawthorn Pit substation via an 1800 MW HVDC symmetrical monopole link. It also connects to Creyke Beck substation via an 1800 MW multi-terminal HVDC symmetrical monopole link which tees into the R4_1 (1500 MW) offshore substation. The Tee-point will work in a similar way to the multi-terminal link in the North West Region.

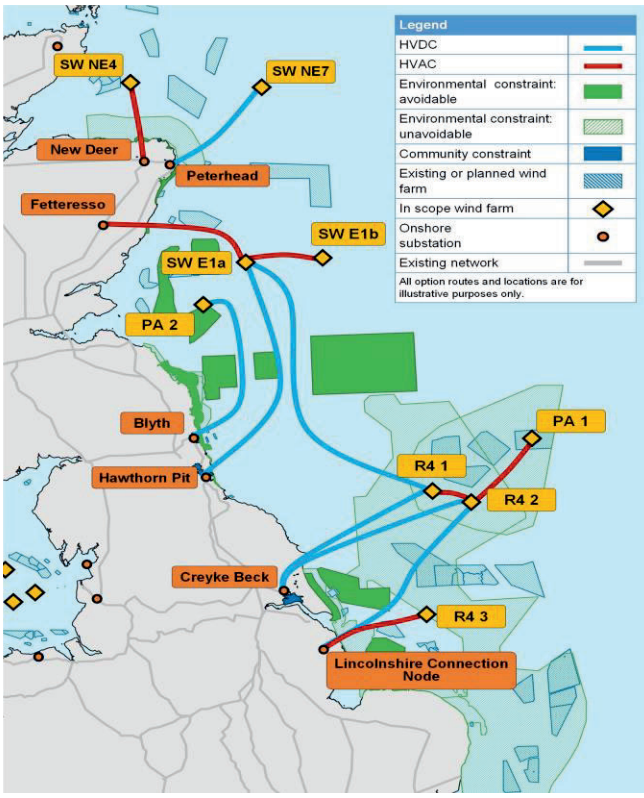


Figure 4: Recommended East Coast Region Design

R4_1 (1500 MW) has a 1500 MW AC link to the R4_2 (1500 MW) offshore substation.

R4_2 (1500 MW) has two 1800 MW symmetrical monopole HVDC links into both the Lincolnshire Connection Node and Creyke Beck substations.

Potentially, there is a mixture of network design configurations in this region. This can be seen by the links connecting the network in Scotland to the network in England, which are similar to subsea onshore transmission circuits such as the planned Eastern Links.

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5.4 South West Region

For the region shown in Figure 5, it would be premature to propose a finalised design, before more certainty is seen on the future Celtic Sea leasing round.

For the purpose of the HND, 1000 MW has been assumed, which is split into three wind farms. This assumption was based on the ambitions for the region at the time of initiating the HND as well as the size of projects that were being developed. The design in this region is based on our assumptions and reflects a shared OFTO with all three wind farms connecting to Pembroke substation.

There are assumed to be two 300 MW wind farms and one 400 MW wind farm. We have assumed all of the spatial locations. The Crown Estate's Celtic Sea leasing round will determine actual project sizes and locations.

Projects requiring a seabed lease in the region are expected to be reconsidered within the HND follow up design process.

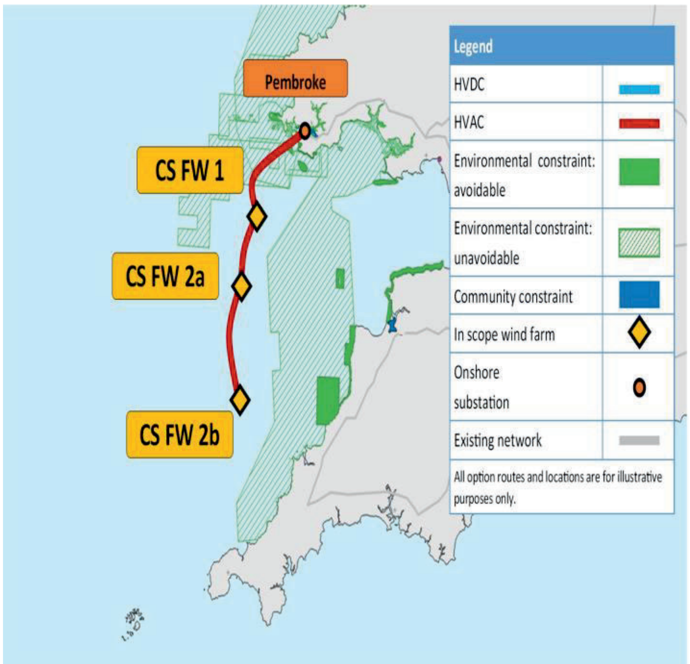

Figure 5: Recommended Indicative South West England Region Design

5.5 Offshore substation design layouts

This section outlines a high-level design of how the offshore substations could look in the HND. This has been used when considering the report recommendations, due to the direct impact these designs could have on the codes, especially the technical codes. These designs will also be subject to the detailed network design stage, which will evaluate exactly how the final layout will be for the HND.

The yellow/orange diamonds seen in the regional diagrams in Section 5.2 to Section 5.5 (Figure 2, Figure 3, Figure 4 and Figure 5 above) represent the potential location of the offshore platform that an offshore wind farm could connect to. These offshore platforms could be double busbar substations at 275 kV. Based on the size of the wind farms, developers will still need to build an offshore collector substation, potentially at 66 kV, with the relevant transformers to transmit the power to the 275 kV substations. The current assumption is that the offshore collector substation will define the offshore grid entry point from the HV side of the transformers.

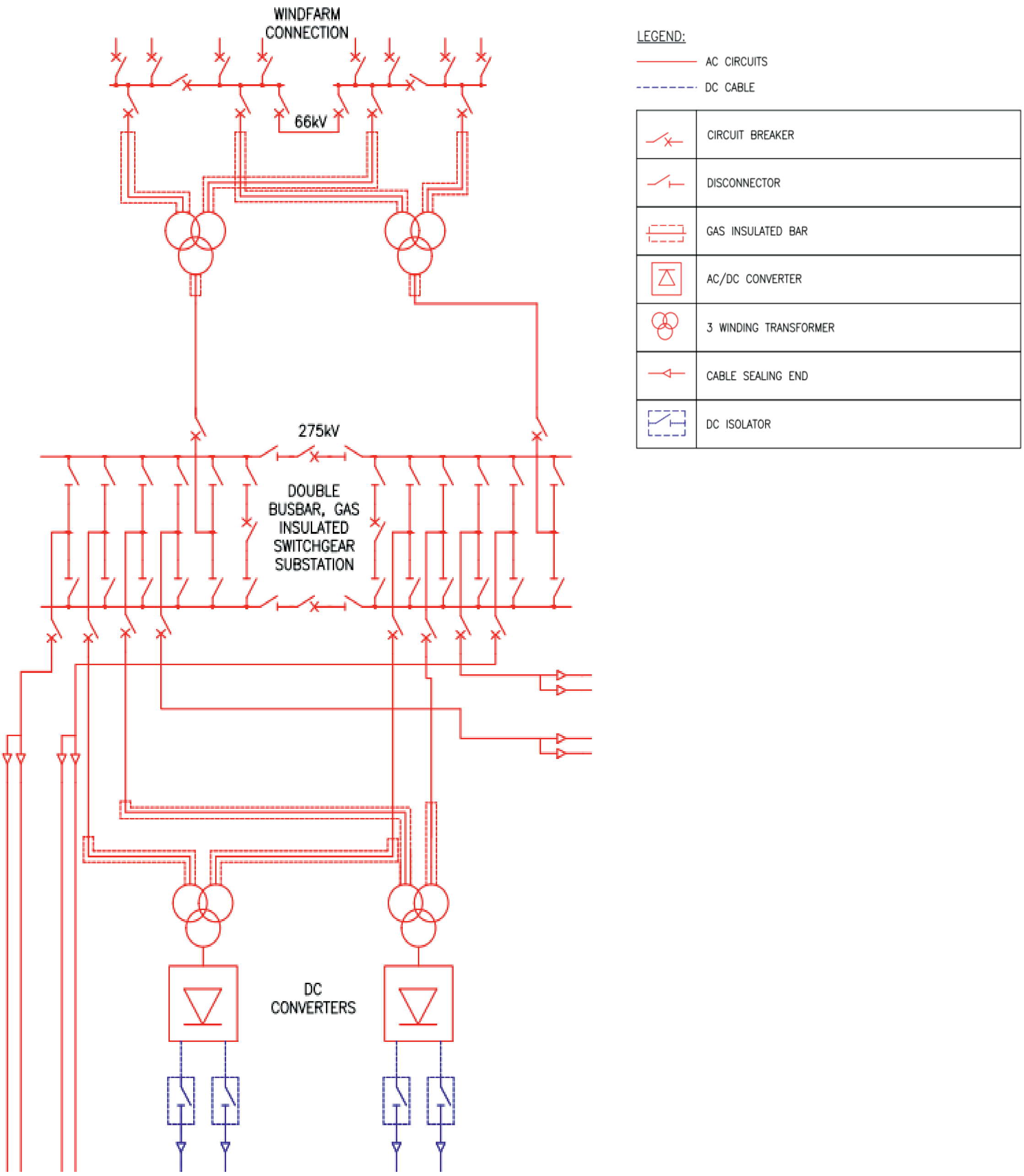

Figure 6: Example Single Line Diagram of an Offshore Substation

These offshore substations, which are not pictorially represented in the coordinated design figures, will then connect to the yellow/orange diamonds mentioned above. Figure 6[28] shows an example of how an offshore substation could be laid out in a Single Line Diagram i.e., in relation to one of the yellow/orange diamonds in the regional diagrams. The design shown in Figure 6 shows the wind farm's 66 kV substation, the 275 kV double busbar substation, two convertor stations and transmissions circuits, subject to the detailed network design stage. For any connection where the wind farm is connecting radially, the design will look similar to Figure 7, as long as current loss of infeed criteria is met for radial connections.

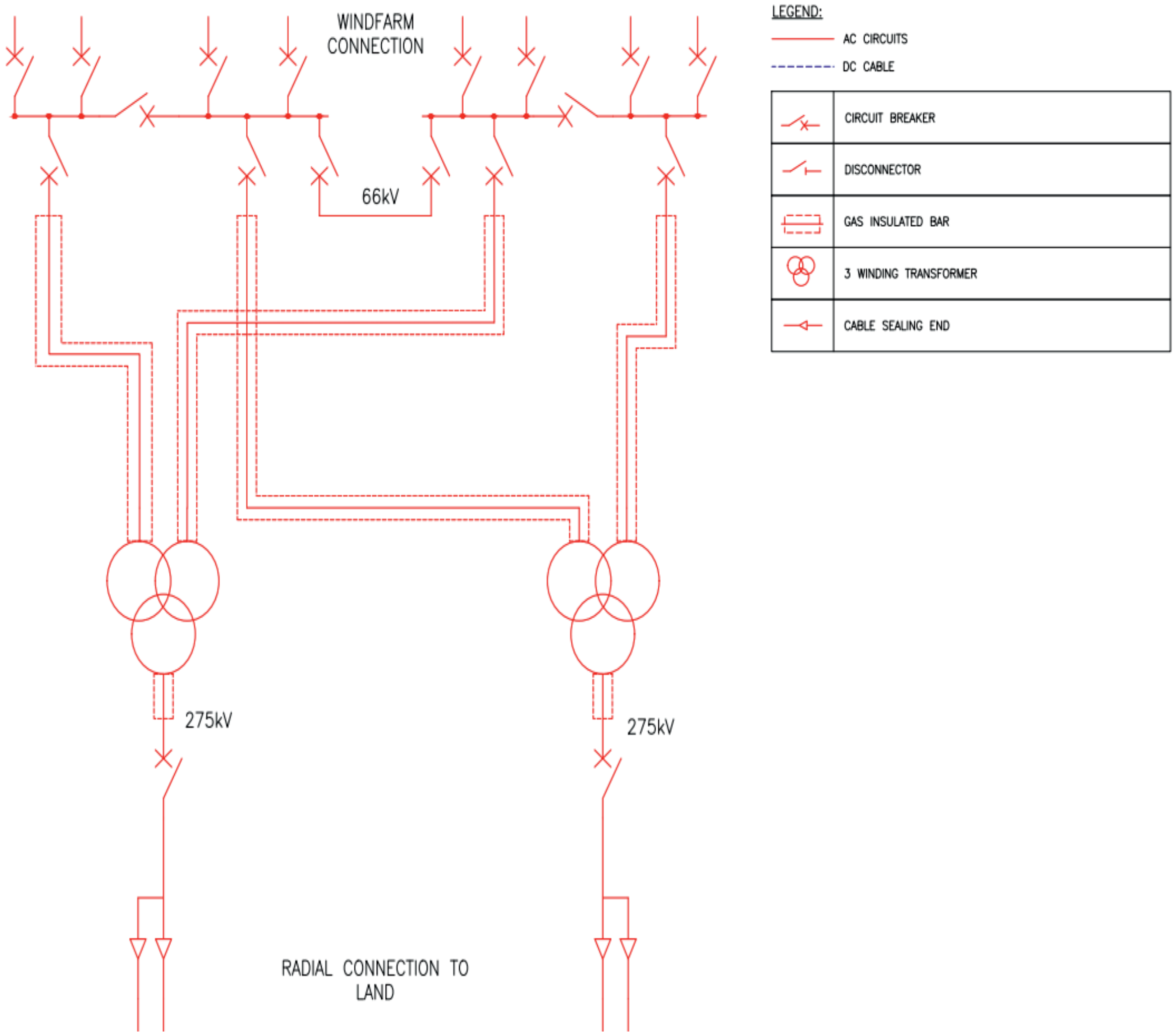

Figure 7: Example Single Line Diagram for a radial offshore wind farm

[28] The substation that the wind farm will connect to is currently a double busbar substation without any reactive equipment. Any additional offshore equipment will be specified once the detailed network design work has been carried out, which will also include any operational impacts that have been identified as part of these studies that affect system frequency and inertia.

6 Technical recommendations

6.1 Overview

This section explores initial views on known or potential changes to the technical codes and standards as a result of the Holistic Network Design (HND) recommendations. These views are not exhaustive, and we invite stakeholders to provide feedback on what has been identified to date, including whether the potential solution is the right one. We are particularly interested in any omissions, including where there could be other potential code and standard solutions. In this section, we explore the Security and Quality of Supply Standards (SQSS), Grid Code and the System Operator Transmission Owner Code (STC) in respect of STC Section K.

6.2 SQSS recommendations

The SQSS sets the minimum requirement applicable for the design of the transmission system. It also offers the flexibility to allow further investment where such investment is justified. It is necessary to ensure that the SQSS remains up to date and that it continues to drive economic, efficient, and coordinated development of the transmission system. It should therefore facilitate the implementation of the design recommended by the HND, provided that there are no unintended consequences that could have negative transmission system impacts. We have identified the following potential areas of interaction between the SQSS and the output of the HND.

The SQSS defines a Direct Current (DC) bipole configuration as a single DC converter. This means that the loss of any part of this DC link with a bipole configuration is required to be treated as an outage of the whole link irrespective of whether the outage affects the whole link or only a single pole. As per Figures 3 and 4, using a 2000 MW bipole to connect SW_W1 in the North West Region and an 1800 MW bipole link to connect PA_2 on the East Coast Region will not be compliant with the loss of infeed risk criteria. It is therefore necessary to revise the SQSS to ensure that these designs become compliant, provided that there are no common modes of failure that would affect the entire link and the loss is limited to a single pole at any point in time. There is also value in a review of the loss of infeed risk criteria applicable to offshore DC converters in order to maximise the opportunity for optimising offshore network designs and minimise the environmental impacts of such designs i.e., an increase of the infrequent infeed loss limit to 1800 MW.

A cap on the loss of infeed risk associated with any single circuit outage of 50 per cent of the capacity of the affected wind farms has been applied for all offshore circuits. The SQSS only enforces this cap for offshore transformers. However, it does not preclude its application to other circuits and in future we may wish to consider whether this cap should be enforced by the SQSS for all circuits.

The current definition of Main Integrated Transmission System covers any network that runs in parallel to the onshore super grid. This means that some of the network in the HND, particularly in the East Coast Region, should meet the requirements of SQSS Section 4 as well as that of SQSS Section 7, where applicable. However, current wider network investment is guided by the Network Options Assessment (NOA) and not directly by the deterministic requirements of SQSS Section 4. The HND follows the same NOA principles so a change to SQSS Section 4 directly for the HND is unnecessary[29].

The SQSS currently specifies that an offshore transmission system extends from an offshore grid entry point to one transmission interface point. To allow for multiple interface points, it will be necessary to introduce some minor, mostly topographical, modifications to SQSS Section 7 and to update the narratives in SQSS Section 1. Such changes are unlikely to be substantial.

We have previously consulted on and published a plan[30] to review the SQSS over the RIIO-2 period and will prioritise addressing the issues that could act as a blocker to the implementation of the designs identified, i.e., the review of the loss of infeed risk criteria and the treatment of bipole configurations in 2022/23. This will be followed by another review to address any other remaining issues.

These recommendations are our initial view related to the SQSS. There may be additional changes which are necessary based on the HND recommendations or because of the above changes.

Q6 Do you agree with our initial analysis on a potential requirement to update the SQSS as above? Do you feel there are any omissions? Please explain your rationale.

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[29] There is currently a plan to review SQSS Section 4, but it does not directly impact the outcome of the HND.
[30] SQSS Review Consultation - www.nationalgrideso.com/calendar/nets-sqss-review

6.3 Grid Code recommendations

Grid Code changes as a result of the HND recommendations will require further consideration, such as in relation to reactive power and voltage control at an offshore grid entry point on non-radial offshore transmission. The Grid Code already contains offshore provisions related to generator build arrangements (i.e., related to OTSDUW and the requirements at a grid entry point offshore, etc) which remain applicable to allow the HND to be effectively delivered with minor changes associated with the preferred offshore delivery model as further considered in Section 4.6.

It is worth noting that future offshore network designs are likely to drive further changes to Grid Code, in particular due to the introduction of new technology and design variants, and/or changes to offshore ownership boundaries. In addition, some further thought may need to be given to the Alternating Current collector network between the offshore wind farm and connection to the wider offshore transmission system, especially generic requirements for reactive capability.

A greater level of paralleling between the onshore and the offshore system will mean greater variability of the flows on the offshore circuits. This may require offshore wind to provide a wider reactive capability range to ensure that voltages on the offshore system could be managed within the applicable limits. From an offshore network design and operational perspective, this will be addressed through SQSS changes as summarised in Section 6.2.

Further consideration will need to be given to the ability to expand the offshore transmission system as this could involve numerous developers and Offshore Transmission Owners. Further clarity will need to be given to different developers through the generator build arrangements, so the offshore transmission system can be built up in a modular way. An electrical standard[31], as referenced in the Grid Code (such as ECC.6.2.1.2), will need to ensure the separate offshore networks built by different developers can be integrated with each other to enable future operation of these assets. Each element of the offshore network will also be required to be compliant with the requirements of the SQSS, Grid Code and STC as applicable.

Q7 Do you agree with our initial analysis on a potential requirement to update Grid Code as a result of the HND recommendations as above? Do you feel there are any omissions? Please explain your rationale.

6.4 STC Section K recommendations

It is anticipated that there will be minimal change required to STC Section K as a result of the HND recommendations. However, any changes in the Grid Code would need to be reflected in STC Section K. The reason being that it is an essential requirement for the generator build arrangements pre-transfer of the assets to an OFTO, to ensure the requirements at the interface site/point are clear to all parties.

We think it is unlikely that other technical areas of the STC will be impacted by the HND other than some additional consequential detail that may be required in the STC Procedures. There could be potential for technical change to STC Section K associated with the offshore delivery model, as is further considered in Section 4.4.

There could also be similar or additional impacts on the STC if future offshore network designs are considered and as explained in Section 6.3.

Q8 Do you agree with our initial analysis on the minimal requirement to update the STC Code as a result of the HND recommendations as above? Do you feel there are any omissions? Please explain your rationale.

[31] Current standards - www.nationalgrideso.com/industry-information/codes/grid-code/electrical-standards-documents

7 Network charging recommendations

7.1 Overview of network charging

Network charging is a codified mechanism for the ESO to recover the cost of building and maintaining transmission assets on behalf of Transmission Owners (TOs) and Offshore Transmission Owners (OFTOs), whilst enabling us to recover the cost of performing balancing services and connecting individual users to the National Electricity Transmission System (NETS). At a high-level, charging can be categorised into three key areas. These being Transmission Network Use of System (TNUoS) charges, Balancing Services Use of System (BSUoS) charges and Connection charges. TNUoS charges recover the costs of building, owning, and maintaining assets for onshore TOs and OFTOs and are applicable to transmission connected generators and electricity suppliers for the use of the onshore and offshore transmission network. BSUoS charges recover the costs of activities related to balancing the transmission system and are paid for by users of the transmission system. Connection charges, which are levied on individual users, recover the costs of installing and maintaining specific assets that connect users to the transmission network.

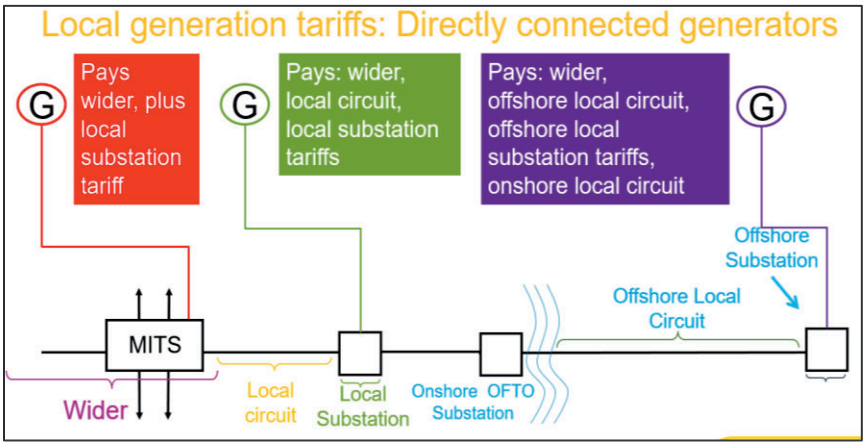
7.2 TNUoS charges

Onshore and offshore generators are subject to TNUoS charges, which are outlined in Connection and Use of System Code (CUSC) Section 14. For onshore generators, TNUoS charges are set based on where they are located, the generation technology, and how they use the transmission network. Transmission connected offshore generators also pay TNUoS charges, which recover a large part of revenue for OFTOs, who are owners of the transmission assets which connect offshore generators to the onshore network.

The regulatory framework for TOs and OFTOs are different and so the charging methodology differs. The onshore charging principles are based on two components - the locational signal tariffs and the non-locational tariff for revenue recovery. The offshore local tariffs are calculated using the actual project costs accrued in the construction of an asset and are targeted at specific users. Offshore generators are subject to the offshore local circuit tariff, offshore local substation tariff and, if applicable, the Embedded Transmission Use of System (ETUoS) tariff. Additionally, an offshore generator will pay wider TNUoS tariffs, and may have an onshore local circuit tariff if the OFTO owned onshore substation is not connected to a Main Interconnected Transmission System (MITS) Node. A summary of the tariffs is outlined below:

- **Offshore local circuit tariff** - this is calculated using the actual costs of the offshore transmission infrastructure (including cable assets, reactive equipment, and harmonic filtering equipment) used by generators to connect them to the onshore network.
- **Offshore local substation tariff** - this is calculated using the actual costs of the offshore substation infrastructure, including the costs of transformers, switch gear, and the platform.
- **Embedded Transmission Use of System tariff** (**ETUoS**) - if the OFTO connection to the MITS Node is via a distribution network circuit, the ETUoS tariff may be applicable. This recovers the costs of any distribution charges paid during the development of the offshore transmission network.
- **Onshore local circuit tariff** - generators which do not connect to a MITS Node will pay an onshore local circuit tariff. This reflects the costs of local network which connect them to the wider network.
- **Wider tariff** - this reflects the cost of different generator types connecting to the wider transmission system in different parts of the transmission network.
- **Adjustment tariff** - this is used to ensure that generation tariffs are compliant with UK regulation. It requires total TNUoS recovery from generators to be within the range of €0-2.50/MWh on average.

The diagram below provides an overview of tariffs applicable to generators dependent on where they connect to the network:



7.3 Current developments in the TNUoS charging methodology

Ofgem has recently published an update on the TNUoS Taskforce[32]. This TNUoS Taskforce will be exploring improvements to the charging methodology without changing its modelling approach or core assumptions.

We are currently in the process of considering any potential overlap between, or alignment with, the work of the TNUoS Taskforce and the code change work associated with the Early Opportunities and Pathway to 2030 workstreams.

To further explore this, throughout Summer 2022 we will engage with the TNUoS Taskforce on potential code changes, as further detailed in Section 10.

7.4 Application of TNUoS tariffs to offshore coordination

The current offshore charging methodology was designed based on radial connections. Therefore, the network designs outlined in the HND were not originally considered. It is important to determine whether the current offshore methodology can be applied to the network designs in the HND, or if there are barriers and challenges which require an update or change to the methodology.

When applying the current CUSC methodology, several key challenges within network charging have initially been identified. There is difficulty in allocating charges between offshore generators who are utilising the same offshore local circuits and substation as this is not explicitly outlined in the CUSC. This challenge can be split into two sub challenges - determining which offshore substations and offshore circuits an offshore generator should pay towards and the method used to apportion costs between two or more offshore generators utilising the same offshore circuit and offshore substation. This is further explored in Section 7.5.

Another challenge is around the methodology being silent on the application of the wider tariff when an offshore generator is connected in parallel to two onshore MITS Nodes which fall into different generation zones. Further context on this challenge is provided in Section 7.6. As outlined in Section 3.8, the first and second challenges have been recommended as code modifications via our Early Opportunities workstream and are applicable to all workstreams under the OTNR. A stakeholder workshop was held on 9 May 2022 to discuss the two challenges further and explore the various options.

In some of the HND, there is potential for onshore generators to utilise the offshore network to move energy to different points in the onshore network, assuming the offshore network is operated in an integrated configuration. Consideration should be given to charging relevant onshore generators for their usage of the offshore circuit in such circumstances. Further information is provided in Section 7.7.

Also, with the HND, an offshore MITS Node may be introduced at various points, which could benefit from an offshore MITS Node definition, which is not currently in existence. This is considered further in Section 7.8. Linked to this, and dependent on the offshore MITS Node definition, the charges paid by offshore generators directly connected to an offshore MITS Node need to be considered.

Currently onshore generators directly connected to a MITS Node are not liable for local circuit tariffs and just pay the wider tariff, but the best approach for an offshore MITS Node needs to be considered. Further information is provided in Section 7.9.

[32] www.ofgem.gov.uk/publications/tnuos-task-forces

The next challenge relates to Anticipatory Investment (AI). If we apply Ofgem's minded-to decision for the allocation of AI in the Early Opportunities workstream as the basis for Pathway to 2030 workstream, the subsequent generator(s) would be responsible for the AI Cost Gap once connected. This requires further consideration. The AI Cost Gap is what would be payable to the OFTO but not recovered in the absence of the subsequent generator(s), so is temporarily recovered from consumers prior to the subsequent generator(s) connecting. It applies for the period between shared asset transfer to an OFTO and the date any subsequent generator(s) are connected to the NETS. Subject to the final decision by Ofgem on this minded-to decision, the principle and detail needs to be outlined in the CUSC to confirm how the payment of the AI Cost Gap is recovered from the subsequent generator(s) for both the Early Opportunities and Pathway to 2030 workstreams. This is further explored in Section 7.10.

Another challenge relates to the generator build delivery model. The generator commissioning clause enables the developer to participate in generation and the conveyance of electricity over an electricity transmission line for 18 months, before the transmission assets have to be transferred to an OFTO. During this 18-month period the primary generator will own and operate the offshore transmission assets. If any subsequent generation is connected during this period utilising the primary generator's assets there may need to be an arrangement and methodology for the subsequent generator(s) to pay the primary generator for utilising these assets prior to them being transferred to an OFTO. There is a question if this arrangement and methodology sits inside or outside of CUSC Section 14, which is explored further in Section 7.11.

With the wider tariff, there are elements that only reflect the characteristics of the onshore network at present. For example, the 'connectivity' between zones that the Transport and Tariff model uses to reflect how the zones are connected. This is an element which is factored into the tariff calculation. However, with the designs in the HND there is the potential for energy to 'jump' between zones being transported via the offshore circuit, and not via the onshore zones. This essentially skews the connectivity element of the wider tariff. Another example is the calculation of the MW loading on circuits for locational tariffs. The calculation methodology is largely based on the nature of Alternating Current (AC) network. So, the current wider tariff charging methodology needs to be reviewed in light of the designs in the HND recommendations and this is further explored in Section 7.12.

We consider each of the above challenges in more detail in the sub-sections below. On Challenge 1, Challenge 2 and Challenge 4 we have already undertaken some initial engagement and we have summarised the feedback from that engagement in those sub-sections.

7.5 Challenge 1 - difficulty in allocating charges between generators

The CUSC methodology does not specifically mention how charges are allocated between offshore generators connected to the same local offshore circuit and/or offshore substation. Also, there are no guidance notes providing details on the method to split offshore local substation and offshore local circuit costs between two or more connected offshore generators. There will also be a need to determine which offshore assets are classed as pre-existing assets for each developer in line with the CUSC.

This challenge can be split into two sub challenges by determining which offshore substations and offshore circuits an offshore generator should pay towards, as well as what method is used to apportion cost between two or more generators utilising the same offshore circuit and offshore substation.

We consider each of these sub challenges in further detail as follows:

Determining which offshore circuit and offshore substation a generation pays towards (Sub-Challenge 1)

With the East Coast Region network design, a generator could flow power via different onshore connection nodes dependent on which offshore circuits and offshore local substations are utilised. This creates a challenge to determine which offshore circuit and offshore substation costs should be allocated to that generator. For example, the generator connected to PA_1 in Figure 4 could flow power onto multiple onshore nodes depending on which offshore assets are utilised in the system.

Clarification is required in the CUSC methodology to determine which offshore assets an offshore generator pays towards when they can use several offshore circuits and offshore substations which can also be used by other generators. Three options for the basis for a code modification have been initially considered on the assumption that offshore circuit and offshore substation costs would be recovered by local charges and not wider charges.

Option 1 - charge the offshore generator for each offshore asset they can use

Under this option for a CUSC modification, each generator would pay towards all offshore substations and offshore circuits they could use as a route to connect to an onshore interface site. The generator's local tariffs would consider the OFTO revenue associated with those offshore substations and offshore circuits. This approach offers a degree of cost reflectivity based on the assets the generator could potentially use in theory, although in practice the generator may not use all offshore assets they are paying towards. Also, this may not be reflective of onshore, where a generator could use another generator's local asset, but this does not have a bearing on charges.

Option 2 - allocating costs by zones

Under this option, the offshore assets (i.e., offshore circuits and offshore substation) and the offshore generators would be categorised into zones. This could be done by either extending the current onshore zones offshore, or by creating new offshore zones. We explore these options in more detail below.

Option 2a - extend current onshore zones offshore

The boundaries for onshore zones would be extended offshore so offshore generators and offshore assets fall into a specific zone. The offshore generator would pay towards all the offshore assets that fall into the zone in which they are located. A methodology would need to be created to determine the criteria for extending out the onshore zones.

Option 2b - create new offshore zones

New offshore zones would be created so offshore generators and offshore assets fall into a specific offshore zone. The offshore generator would then pay towards all the offshore assets that fall into the zone in which they are located. Again, a methodology would need to be created to determine the criteria to develop new offshore zones. Both options 2a and 2b have the benefit of being easier to apply once zones have been created. However, this may not be cost reflective as the offshore generators could be using offshore circuits and offshore substations in other zones that they are not paying towards, and it will have implications or interactions with the wider zonal methodology. It will also require wider engagement/debate to create a methodology to determine how to extend onshore zones offshore or to create new zones offshore as it impacts more users.

Option 3 - pay for offshore circuits and offshore substation costs based on volume of energy metered

This option would be to use the volume of energy metered from the offshore generator to any offshore circuit and/or offshore substation which have been utilised before reaching the onshore interface site. A mechanism would be required to measure the metered energy at each interface point between the offshore generator, offshore substations, and offshore circuits. Prior to any data being available, a forecast and an agreed methodology would need to be developed to determine the flow of energy from each generator. Once the generators have been connected for a certain period (such as one year) the data from this period could be utilised going forward. This would be the most cost reflective option as actual use would be a key deciding factor when determining which offshore substation and offshore circuit the generator pays towards. This option lacks simplicity, is not easy to understand and could be very complex to implement as proving route of flow is difficult even if it was metered at each asset. Therefore, assumptions will have to be made in terms of route of flow, but this could be open to debate. This approach would create a new principle in the CUSC methodology which would take time to determine the details and implement.

Allocating charges between two or more generators utilising the same offshore assets (Sub-Challenge 2)

Within the HND, there are network designs where two or more generators are connected to and utilising the same offshore local circuit and/or offshore local substation. For example, in the East Coast Region the generators connected at PA_1 and R4_2 can utilise the offshore circuit between R4_2 and R4_1 in Figure 4.

There is no method outlined in the current methodology to determine how charges would be apportioned between two or more generators. An approach needs to be created to determine how offshore local circuit costs and offshore local substation costs are split between offshore generators.

To overcome this challenge, a CUSC modification is recommended to outline a process to split costs between generators in a non-discriminatory manner, whilst ensuring costs are fully recovered. Three key elements to consider when determining the basis of a modification are the use of the circuit and substation, the generators benefiting from that use and the Transmission Entry Capacity (TEC) of the generators connected.

We will also need to be mindful of any future decisions on AI for Pathway to 2030 from Ofgem and future decisions on AI on Early Opportunities (related to the minded to decision already published on AI) and how it links to network charging and this challenge.

We have explored three options as a basis for a code modification to allocate charges between two or more generators utilising the same offshore assets.

Option 1 - sharing via TEC

This approach would be to split the costs between the two generators purely based on their TEC. This approach is simpler than the alternatives below since it uses the existing CUSC calculations but clarifies that it will also be used where more than one generator shares use of the same assets. Each generator's liability would be in proportion to their TEC, so a generator with a higher TEC value compared to another generator would have a larger annual liability. This would enable the appropriate level of revenue recovery and bring in an element of cost reflectivity, although perhaps not to the same extent as the approach in Option 2. Option 1 will be simpler to develop and manage as the TEC is likely to be a stable value.

Option 2 - measure of likely output

A new set of sharing principles via a 'measure of likely output' could be outlined in the CUSC. When two or more generators utilise the same offshore circuit and/or offshore substation, they would be responsible for their share of charges from the date assets are transferred to an OFTO. The proportion of charges each generator would pay will be based on their measure of likely output which is calculated by multiplying together their TEC and Annual Load Factor (ALF). If one generator had a higher measure of likely output, they would pay a higher proportion of charges than another generator with a lower measure of likely output. This approach would enable the appropriate level of revenue recovery, whilst also providing some level of cost reflectivity by charging the generator who is likely to utilise more of the asset, due to their higher measure of likely output, a higher level of charge. However, as the ALF data could be susceptible to change on a yearly basis, it could lead to a level of tariff volatility.

Option 3 - proportion charges based on volume of metered energy

This option is to apportion charges between generators based on the volume of energy which flowed from the generator via the offshore circuit and/or offshore substation. Additional metering would be required to track the flow of energy from the generator to shore. Prior to any data being available a forecast would need to be developed to determine the flow of energy from each generator. A method for creating the forecast would also need to be developed. Once the generators have flowed for a certain period (such as one year) the data from this period could be utilised going forward. The metered data would allow charges to be split between generators. If metered data from the primary generator is higher than metered data from a subsequent generator, the primary generator would have a higher proportion of charges.

This is a more cost reflective approach from the perspective of taking usage of the offshore network into account. The difficulty would be to install additional meters to obtain the metered data and apportion the flows to individual generators in an integrated network, so it could be quite complex and expensive to implement.

An OTNR charging workshop was held with the industry in May 2022 to obtain feedback on the challenges and the options for modifications. Feedback from the workshop suggested Option 1 - Sharing via TEC - was the preferred solution due to being the least complex option and as TEC is currently used for various charging principles. For a more detailed summary of the feedback from the May 2022 charging workshop, please refer our *Stakeholder Approach, Engagement and Feedback Report* for further information.

Other considerations (Sub-Challenge 2)

Consideration of options from a calculative perspective

When testing the modification options above with worked examples, all approaches work from a calculative perspective and ensure an appropriate level of revenue is recovered from the relevant generators. Option 1 uses the current calculations with no variation. It applies the tariff that is calculated to each of the generators that are using the system. This means that the revenue collected from each generator will be in proportion to their TEC. Options 2 and 3 involve additional input data and calculations to inform the relevant proportional approach to splitting the revenue collected between the generators. These options are not difficult to implement, subject to data availability and quality, although this could introduce complexity. Each of the three approaches recover an amount of revenue that aligns with the current methodology. Consequently, it is more important to focus on identifying the best solution based on principles. For example, which solution is most cost reflective, rather than on the outcome of calculations.

AI and a separate share of OFTO Allowed Revenue (AR) for each generator

It is assumed there is a single OFTO AR value for the asset, so a methodology would need to be created to apportion costs between two or more generators. If Ofgem could potentially provide a separate OFTO AR component for each generator/developer, the local offshore substation and local offshore circuit tariff could be based on the capital value for the respective generators. This could mean a specific and different amount of revenue is required to be collected from each generator, taking into consideration the amount that is shared via the demand residual with consumers. To ensure a specific amount of revenue collection for each generator, the calculative methodology would need to be reviewed to facilitate such arrangements. Therefore, it is likely a CUSC modification will be required. Once further information emerges on the details of AI for the Pathway to 2030 workstream, which could potentially be different to that related to Early Opportunities, the impacts and need for modification can be further examined.

Consideration of reason behind offshore network investment

With the options above there is the potential for some of the circuits and substations within the HND to be built to a greater or lesser extent for the purpose of boundary reinforcement. Certain circuits and substations would not be built solely for specific generators but also to provide a wider system benefit. Therefore, within these options, consideration could be needed to reduce charges for certain generators where the boundary reinforcement increases their offshore circuit and offshore circuit tariffs. As more is known about the purpose of the offshore network investment, this point can be further considered.

7.6 Challenge 2 – charging methodology being silent on the relevant wider tariff to be applied

The wider tariff revolves around the principle of sending locational signals and therefore the tariff can vary between different geographical zones. Generators onshore and offshore pay the wider tariff which is determined by the zone of the MITS Node the offshore generator is connected to. If an offshore generator can only flow to one MITS Node, then the offshore generator will pay for the wider tariff based on the zone the MITS Node sits in. When an offshore generator can flow into two or more MITS Nodes concurrently, and when the MITS Nodes falls into different generation zones, there is no direction or guidance in the methodology confirming which wider tariff is applied.

Within the HND, there are network designs where a generator can flow into two or more different MITS Nodes concurrently. For example, in the East Coast Region we assume that all generators in Figure 4 can flow into multiple connection points, which are in different generation zones. Therefore, it would need to be determined which wider tariff is applied. A change to the methodology is recommended in the form of an addition or clarification to determine which wider tariff is paid. Below we explore some initial options as the foundations for a code modification along with a brief assessment of each option.

Option 1 - identify a master route

A criterion would need to be established to identify the master route for all routes available from the generator to the MITS Nodes. The generation zone of the onshore interface site the master route connects to, would determine applicable wider zone to be used. This option would provide clarity on which zone is applicable to each generator and would not require a significant change to the methodology. It would require the introduction of criteria to define the master route. Under the generator build mechanism:

(a) prior to the point that offshore circuits are transferred to an OFTO, they are deemed to be part of the generator's assets. They may be required to operate under the radial configuration for technical reasons, and the radial configuration will naturally then determine the "master" route.

(b) after asset transfer and/or when the offshore network is operated under the integrated configuration, deciding upon a criterion to determine the master route could become more complicated and challenging.

Option 2 - wider tariff is based on distance

With this option, distance would be the key parameter to determine the wider tariff. The distance between the generator and each MITS Node would be calculated to determine the shortest route. The MITS Node and associated generation zone of the shortest route would be used for the wider tariff. The distance would be measured using the circuit lengths utilised for the route so circuit data would be required. Prior to the assets being built the network designs could be used as a basis to determine the circuit lengths. This option has the benefit of being fairly simple to calculate, as long as the data is available. The distance will not change unless there is reinforcement work required. As the distance would be a constant value, the MITS zone will not change. Therefore, this leads to better predictability and offers a form of stability in the wider tariff.

This approach may not reflect network usage as all or most of the flow of energy could be via the circuit which has the longest route, but a generator could still be charged on the shortest route. There is a risk that the "preferred option" may change during the project build stage, and thus the assumed route length will change accordingly. There could also be challenges around different methods to calculate the distance, and one method may reveal a shortest distance compared to another method. This could be overcome by descriptive legal text confirming the method to calculate the measurements.

Option 3 - split charges

A split option could be created to take into consideration all the generation zones of the MITS Nodes the generator is connected to. Two sub options have been considered here - 3a) a split option which is equally weighted, and 3b) a weighted average based on distance. We explore each in more detail as follows.

Option 3a - split charging base which is equally weighted

This would be the simplest approach. Where a generator is connected to two MITS Nodes, they would pay the tariff based on one generation zone according to 50 per cent of their TEC and the tariff based on the other generation zone according to the remaining 50 per cent. This method has the benefits of being simple, transparent, and easy to scale up if required. It would also mitigate the risk of challenges related to which wider tariff should be applied. Additionally, the number of generation zones would not change unless there are further connections to different zones, but again this would be easy to scale. This approach does have the disadvantage of not taking network usage into consideration.

Option 3b - split based on weighted average of distance

With this approach the split of each zonal charging base would be based on the distance of the generator to each MITS Node. The distance for each route would be calculated and then given a weight factor. This weight factor expressed as a percentage for each route would then be multiplied by the TEC of the generator. An illustrative example is outlined as follows.

Route A =100km, Route B = 130km,

Generator TEC = 100 MW

Weight = (Route A or B / Combined length of both routes) x 100

Route A weight = (100/230) x 100 = 43%

Route B weight = (130/230) x 100 = 57%

Weighted average = Weight x TEC

Route A = 43% x 100 = 43

Route B = 57% x 100 = 57

Each route's weighted average would then be applied to the wider tariff which would be determined by the generation zone of the MITS Node the route utilises. This option would be fairly simple to calculate and once built would not change unless the generator connects to more MITS Nodes. Importantly, this approach would start to take into consideration locational factors. It would also consider network usage, but perhaps only to a small degree, so there would be some element of cost reflectivity. As with the above options it will still be susceptible to other variable factors in the wider tariff, creating a degree of volatility.

Option 4 - determined by base load

This option involves looking at the base load and using actual power flows to determine the amount of energy flow to each MITS Node the generator is connected to. The split between the wider tariffs would be determined by the amount of flow to each MITS Node. So, for example if 80 per cent of the flow was to one MITS Node, 80 per cent of this wider tariff would be applied, with the remaining 20 per cent to the other MITS node. This would then be multiplied by the TEC of the generator before applying the wider tariff based on the generation zone the MITS Node was located in. Prior to the transfer of assets to the OFTO, flow data would be limited or not available, so the flow data could be based on a similar generator or power flow could be forecasted before actual data from that generator is available. When actual flow data is available and utilised, this approach would the most cost reflective as it takes into consideration actual network usage. This option is potentially more complicated to implement if the flow data is not easily accessible or only partial data is available. In addition, as the network becomes more integrated and it starts to resemble the onshore network, it could be more and more difficult to track and calculate the load flow. As base load could vary each year, this could be reflective of network usage but also create volatility in tariffs.

Option 5 - extending onshore charging zones offshore

With this approach the onshore generation zones would be extended offshore. A methodology would be developed to determine how each generation zone would be extended offshore. The zone the generator was in would determine the wider tariff to be applied. This would help to align to the onshore methodology and could cope with any size and scalability for the future if the offshore network extends further. This option also has the advantage of being well understood as it is used onshore. A drawback of this approach would be the challenge around determining how each zone is extended, and both the parameters and assumptions that are used to set wider tariffs. It could also require a further CUSC modification outlining the methodology to extend zones offshore and calculate offshore wider tariffs. Furthermore, this would be more time consuming to implement as it may require a wider and potentially a more fundamental discussion on TNUoS methodologies, and a lot more data and modelling work to incorporate the extended zones, creating additional complexity.

Option 6 - creating new offshore charging zones

Under this option new generation zones would be created offshore, extending the principles of zones onshore to offshore. Again, a methodology would need to be developed to determine how the new zones were created. Also, for the new zone, a new wider tariff would need calculated specifically for that zone. The new zone the generator was in would determine the wider tariff to be applied. This would help to align to the onshore methodology and could cope with any size and scalability if the offshore network further extends in future.

Industry feedback from the charging workshop mentioned in Challenge 2 suggested each option has a degree of complexity and although there was not a strong preference for an option, creating new offshore zones (Option 6) seemed to be the most supported approach.

7.7 Challenge 3 – charges to reflect onshore generators utilising the offshore circuit

Within the HND, some of the network designs have the potential for onshore generators to utilise the offshore network to move energy to different points in the onshore network, assuming any circuit breakers are closed. For example, in the East Coast Region in Figure 4, energy could move from an onshore generator in Scotland, through Fetteresso and along the offshore circuit, passing SW_E1 and back onshore at Hawthorn Pit in England to supply demand in that area. So, consideration should be given if onshore generators should pay for utilising the offshore circuit and offshore substation to reflect their ability to utilise the offshore network. When considering whether to charge onshore generators for utilising the offshore network, two options have been considered as follows:

Option 1 - charge onshore generators to utilise these elements of the offshore system

This option is to charge onshore generators to utilise the offshore system providing boundary flows. In theory and in practice onshore generators could be utilising the offshore circuit. However, in an integrated network it would be difficult to prove route of flow and how often the offshore circuits are utilised. To determine the correct percentage of offshore system costs to allocate to onshore generators a new methodology would need to be created.

A methodology to determine charges would include a forecast of the volume (MW) of onshore generation utilised by the offshore circuit. Once this is determined, this volume could be converted into a value to determine how much of the offshore circuit and substation costs are allocated to the onshore generators. For example, via a percentage of utilisation. It is important to recognise that in an integrated network, attributing circuit flows to individual users is not always possible. For the purpose of charging, a methodology needs to be established and agreed to allocate circuit flows to individual users in a transparent way.

Determining an appropriate method which is reflective would be essential to ensure cost reflectivity. In terms of allocating a percentage of offshore substation and offshore circuit costs to onshore generators, this could be facilitated through the wider tariff or a separate charge. The appropriate tariff to recover costs from onshore generators will need to be considered further as recovering via the wider tariff may mean further recovery from other offshore generators who also pay the wider tariff. Recovery via a separate charge would require consideration in terms of the appropriate level of decrease in tariffs from offshore generators to ensure there is not an over recovery of revenue.

This option may potentially have the benefit of being more cost reflective to highlight the fact that onshore circuits and offshore circuits are utilised by many generators in an optimal way.

This option would require a change to TNUoS methodology and therefore a CUSC modification would need to be raised to recover offshore network costs from onshore generators.

Alternatively, a portion of the OFTOs' revenue, to be determined by Ofgem, could be allocated to onshore users, similar to today's practice with OFTOs' onshore substations, and thus the offshore users collectively get a "discount" on their offshore charges. However, this approach could be challenging to implement due to the generation cap limiting tariffs to €2.50EUR/MWh.

Option 2 - do not charge onshore generators to utilise these elements of the offshore system

With this option, generators would not be charged for potentially utilising the offshore circuit. No modification would be required, and offshore generators would pick up the costs of the offshore circuit as per today. This option may not be cost reflective, with offshore generators paying for the offshore system which could be used by onshore generators.

7.8 Challenge 4 – consideration of an offshore MITS Node definition

CUSC Section 14.15.33 defines 'MITS Node' as:

'Grid Supply Point connections with two or more transmission circuits connecting at the site; or connections with more than four transmission circuits connecting at the site.'

If we applied the latter part (i.e., more than four transmission circuits) of the definition to the offshore network designs, such as in the East Coast Region, there could be the creation of an offshore MITS Node. SW_E1a in Figure 4 has more than four circuits connected to it, so it could be considered as an offshore MITS Node.

Therefore, it is important to consider if there is a requirement to introduce a new offshore MITS Node definition. We need to consider whether the MITS Node definition remains fit for purpose to offshore and if not, a suggestion to introduce an offshore MITS Node may be required.

If a new offshore MITS Node definition was created, thought must be given to whether the definition should mirror the onshore definition. This will be dependent on the technical differences between an onshore and offshore MITS Node. Additionally, the ownership structures would differ as the onshore MITS Node would be owned by the onshore TO, whereas the offshore MITS Node would be owned and operated by the OFTO.

It is also worth noting that the fundamental characteristics and obligations of TOs and OFTOs differ slightly. For example, offshore networks are designed to have only 50 per cent of circuit redundancy, while the onshore network is designed to have higher level of redundancy. Another example is that OFTOs and TOs are regulated differently, with the former having a tender revenue stream for 20-25 years versus the latter having a price control period which is much shorter, albeit with assets being depreciated over a longer period.

Another key consideration from a charging perspective is that onshore generators directly connected to the onshore MITS Node do not pay local circuit costs as there is no local circuit being used before connecting to the MITS Node. However, applying this principle to an offshore MITS Node may not be viable as the offshore generator is likely to still use an offshore circuit to transport energy onshore. The charges generators directly connected to an offshore MITS Node should pay is further explored in the next challenge below.

With the question around an offshore MITS Node definition, there are two options.

Option 1 - create a new offshore MITS Node definition

The first option is to create a definition for an offshore MITS Node, which is distinct from the onshore MITS Node definition. This would be based on the technical characteristics and charging implications mentioned above. A methodology change would be required to create this definition.

Option 2 - extend the onshore MITS Node definition offshore

The second option is to extend the latter part (i.e., more than four transmission circuits) of the onshore MITS Node definition offshore so one approach is utilised for both onshore and offshore. Initial interpretation of the latter part of the current definition is that it can be applied offshore as currently stated. A further deep dive is required to determine if a subtle change would be required in the methodology to make this clear in its application.

Industry feedback from the charging workshop (outlined in Challenge 1) favoured Option 1 - create a new offshore MITS Node definition - as it was clean and distinct, specifically for an offshore MITS Node.

7.9 Challenge 5 – generator charges if directly connected to an offshore MITS Node

As stated in Challenge 4, onshore generators directly connected to the MITS Node do not pay the local circuit tariffs. We need to consider whether this philosophy should be extended to offshore generators directly connected to an offshore MITS Node. If we consider the design in the East Coast Region in Figure 4, SW_E1a will have an offshore generator connected to the offshore substation. Assuming the SW_E1a offshore substation is an offshore MITS Node under the current MITS Node definition, the offshore generator directly connected would technically only be liable for the wider tariff and not the offshore local circuit tariffs. Dependent on the principles developed in Challenge 1 above, the generator connected to the SW_E1b substation would be paying for the local circuit tariff for using the offshore circuits between the SW_E1b substation and Fetteresso, as they would not be directly connected to an offshore MITS Node. However, the generator connected to the SW_E1a substation may not pay the local circuit tariff as they could be directly connected to an offshore MITS Node. They would still be using the offshore circuits between the SW_E1a substation and Fetteresso. So, extending the charging principles related to local circuit tariffs offshore may not be fair and cost reflective for their use of that offshore circuit.

The cost of the offshore circuit could be included in the wider tariff, but this would only be a partial liability for their share. To ensure cost reflectivity, it is important that the offshore generator connected directly to a MITS Node is charged for utilising the offshore circuit. Two initial options are considered to facilitate as follows:

Option 1 - apply the current methodology

Apply the current methodology so the offshore generator connected to a MITS Node still only pays the wider tariff, but this wider tariff now includes the offshore circuit and substation cost that the generator will be utilising. Due to the cap applied on the wider tariff limiting the amount that can be charged per MWh, a significant portion of the OFTO revenue will have to be paid by demand users. This could mean the tariff may not be reflective of the full/appropriate costs of the offshore circuit and offshore substation. In addition, others paying the wider tariff in the relevant zone would also be picking up a proportion of those costs.

Option 2 - exception to the current rule

Dependent on the offshore MITS Node definition, an exemption could be made to the rule so offshore generators connected directly to an offshore MITS Node still pay the local offshore circuit in the same way as they would if it were not classified as an offshore MITS Node. This would enable a more cost reflective approach than Option 1, helping to recover a more appropriate level of offshore circuit from the offshore generator for the assets between the offshore MITS Node and the onshore MITS Node.

7.10 Challenge 6 – the Anticipatory Investment Cost Gap

Ofgem's consultation on their minded-to decision on Anticipatory Investment (AI) outlined how changes would be made to AI to help facilitate the OTNR for the Early Opportunities workstream. We are using the high-level AI principles outlined in this consultation for Early Opportunities as the assumed basis for the Pathway to 2030 workstream in respect of the treatment of any AI Cost Gap related to the HND.

The consultation advises *'in the period between the shared asset transfer to the OFTO and the date that later user connects to the system and starts using the assets funded by the AI, there is a portion of the AI element of the offshore generator TNUoS tariff which will not be paid. However, the equivalent amount will be payable to the OFTO because the costs of the infrastructure form part of the asset value to the OFTO.'* This difference between what is payable to the OFTO but what is not recovered in the absence of a subsequent generator is known as the AI Cost Gap. The consultation goes on to say that the AI Cost Gap liability should be allocated to the subsequent generator (or, we assume, generators) once connected to the offshore transmission system. Until such time as the subsequent generator(s) start to pay TNUoS charges, the risks associated with the AI Cost Gap shall be met by consumers.

From a charging perspective, between the time of the asset being transferred to an OFTO and the subsequent generator(s) connecting, the AI Cost Gap will be funded by the consumer via the demand residual. The subsequent generator(s) will accrue liability of charges for the AI Cost Gap from the point of asset transfer to the connection of the subsequent generator(s). Once connected, the subsequent generator(s) will pay for accrued liability to cover the AI Cost Gap via their TNUoS charges. To facilitate this approach a CUSC modification is required to build in a provision of accruing liability for the subsequent generator(s) to pay for the AI Cost Gap. The AI Cost Gap could be paid as a one-off cost by a subsequent generator in the first year of connection or the costs could be spread over a number of years and paid over that period of time.

This has the benefit of incentivising the subsequent generator(s) to avoid delaying their connection because it will have sole liability for their AI Cost Gap charges, which will continue to accrue until they connect. The longer the subsequent generator(s) delay their connection, the longer they will accrue charges for an asset they are not currently utilising. It could also have a negative impact, as the longer they delay, the higher the accrued charges will be. There may be a small risk that the generator will be incentivised to terminate to avoid the charge, and this will need careful consideration. However, this is considered in respect of User Commitment arrangements in Section 8.3, which sets out how this risk would be mitigated to protect consumers. In the event the User Commitment arrangements do not cover the full amount of the AI Cost Gap, any residual amount could be picked up by consumers, such as via the demand residual.

7.11 Challenge 7 – generator commissioning clause

The generator commissioning clause in The Energy Act 2013 enables a developer to participate in generation and the conveyance of electricity over an electricity transmission line for 18 months before the transmission assets must be transferred to an OFTO. During this 18-month period the primary generator will own and operate the asset and only be liable for the wider tariff (and not local tariffs) in TNUoS. If a subsequent generator connects during this period, they will also be liable for just the wider tariff. However, the subsequent generator may still need to have an arrangement in place to pay the primary generator for utilising this asset within the 18-month period. Therefore, a methodology determining the payment (if any) from the subsequent generator to the primary generator, for use of the offshore transmission assets, may need to be created. There is a question whether this methodology sits inside the CUSC or outside it via a separate agreement. Three options have initially been identified as follows:

Option 1 - methodology sits inside the CUSC

This agreement sits inside the CUSC. The methodology would outline the principle, method to calculate payment, and payment terms. A CUSC modification would be required to facilitate this approach. This option would enable a consistent approach for all offshore generators connecting in the 18-month window. However, it will not consider all scenarios, so the one size fits all approach may not be suitable.

Option 2 - methodology sits in separate agreement

Here, the agreement sits outside of the CUSC methodology. Key elements mentioned in Option 1 above will be included in a separate agreement between the primary generator and subsequent generator(s). This would likely not require a CUSC modification, although this would require validation. This option enables a specific payment methodology to be tailored to the assets and the respective generators. However, as the details of the payment arrangements would sit outside the CUSC, it may not be transparent and therefore lead to a lack of consistent application. Elements of this this are also further considered in Section 4.2.

Option 3 - principle sits inside the CUSC but methodology in separate agreement

This option is a combination of Option 1 and 2 above. With Option 3, the principle would sit inside the CUSC, where the methodology would outline at a high level that the subsequent generator(s) should pay the primary generator based on the principles of the TNUoS methodology. However, the exact details of payment along with payment terms would sit in a separate agreement between the two (or more) generators outside the CUSC. This option would still require a CUSC modification to ensure the high-level principle of the subsequent user(s) paying the primary generator is outlined in the code.

7.12 Challenge 8 – wider tariff connectivity element and impact on Transport and Tariff Model

With the wider tariff there are elements that only reflect the characteristics of the onshore network at present. One element is the ‘connectivity’ between zones that the Transport and Tariff model uses to reflect how the zones are connected. This is an element factored into the tariff calculation. For example, if energy is flowing from Fetteresso in Scotland to Creyke Beck in England onshore, the power is routed through the respective zones between the two points.

However, with the network design in the East Coast Region in Figure 4 there is the potential for the energy to go from Fetteresso to Creyke Beck via the offshore circuit and not via the onshore zones. This essentially skews the connectivity element of the wider tariff so the current wider tariff charging methodology may not be suitable with the HND. This will also have a negative impact on how the Transport and Tariff model works, which is used to calculate the wider tariff. Another example is the calculation of the MW loading on circuits for locational tariffs. The calculation methodology is largely based solely on the nature of an AC network.

Therefore, it is important to review the wider tariff methodology more holistically to ensure that it is suitable for the expanding offshore network. As a CUSC modification, which looks at a specific element such as connectivity in isolation, may not provide the right solution as it may impact other areas of the wider tariff, a broader review of the wider tariff may be the more suited approach. The key elements included in the wider tariff review in relation to the offshore network need to be considered along with the potential for interactions with the TNUoS Taskforce.

What next for each of these challenges?

As further described in Section 10, we plan to further consider and engage upon each of these challenges prior to developing and raising code modifications as and where required. This will also need to be mindful of the ongoing work in relation to the Early Opportunities workstream, as well the TNUoS Taskforce. We welcome views from stakeholders on any of the above potential challenges or any other network charging related challenges which may require consideration as a result of the HND recommendations.

Q9 Are the eight network charging methodology challenges related to the HND above the right focus areas and are there other considerations for CUSC Section 14?

Q10 Do you agree with the modification options considered for the eight challenges outlined in Section 7, and which option would be the preferred solution for each challenge and why?

Q11 Which of the eight network charging methodology challenges should be prioritised and why?

7.13 Other charges and their application to offshore coordination

The transmission licence enables revenue to be recovered for balancing services activity via BSUoS charges. Balancing activity involves balancing the transmission system, including the operation, procurement, and use of balancing services. In April 2022 Ofgem approved CMP308[33], which removes liability for BSUoS charges from all generators from 1 April 2023. Therefore, BSUoS charges will no longer be applicable to offshore generators and as such no methodology change will be required due to the HND recommendations.

Connection charges recover the costs of installing and maintaining connection assets. Connection assets are non-sharable assets installed for and only capable of use by an individual user and hence represent a shallow charging regime. They are calculated annually and consist of capital and non-capital components. We do not believe changes are required to the connection charging methodology due to of the HND recommendations.

7.14 Application fees and application fee reconciliation

The HND is a coordinated design, which provides a connection design for in scope generators. As such, no individual post-signature Connection and Infrastructure Options Note (CION) will be undertaken. This means that no individual CION related costs that are payable via the application fee will have been incurred by those who have applied for a connection. Nevertheless, application fees will have been paid by each applicant and costs will still have been incurred by the ESO and TOs in designing the HND in lieu of designing each CION. Therefore, an alternative way of apportioning costs incurred in providing a connection needs to be in place.

During a CION process all applicants first receive an initial holding offer from the ESO and the fees for the related works are recorded by the ESO and TOs. Projects which subsequently accept this offer and move onto the more detailed post-signature CION process stage incur the bulk of their application fees at that stage i.e., where most of the work is carried out by the ESO and TOs in association with the CION process. The costs, at charge-out rates for both stages, are calculated and reconciled against the original application fee previously levied on applicants.

The HND intends to work in a similar way whereby all applications will be liable for costs incurred by the ESO and TOs in providing their holding offer. However, we are considered how the successful applications, such as those with a relevant seabed lease option and within the HND, will also incur a proportion of the HND development costs. Given the holistic nature of the design, the costs are likely to be split equally amongst successful projects in the HND, and not be weighted by the region or the capacity of a project.

These proposals require further consideration. We are working with the TOs to enable us to engage with impacted developers on these proposals and the mechanics of the application fee reconciliation process in respect of the HND.

[33] www.ofgem.gov.uk/publications/cmp308-removal-bsuos-charges-generation

8 Commercial code recommendations

8.1 Access rights, restrictions on availability and loss of access

Access rights onshore are determined by the extent to which a connection to the National Electricity Transmission System (NETS) is built to Security and Quality of Supply Standard (SQSS) specifications, or whether there is a design variation[34]. If there is a design variation and there isn't the redundancy in the connection as specified in the SQSS there will be Restrictions on Availability (RoA) for certain circuits defined in the connection contract. As the generator has accepted this potential unavailability it means that should a planned or unplanned outage occur on those circuits, then there will be no compensation for the generator.

Conversely, if there is redundancy in the connection, and / or certain circuits are not subject to RoA and an outage occurs, the generator may be able to seek compensation through an interruption payment via a loss of access claim in accordance with the Connection and Use of System Code (CUSC). The associated rights and obligations are documented in connection contracts and within industry codes. For example, whether and to what extent the generator has the right to compensation, etc.

The criteria for generation which is connecting to the offshore transmission system is governed by SQSS Section 7, rather than SQSS Section 2, for onshore. This allows offshore generation to connect with less redundancy than onshore generators without a design variation. This means the offshore generators can connect to and generate onto the NETS potentially quicker and with less infrastructure investment than would otherwise be needed. However, it does mean their access will be at least in part curtailed if there is a relevant outage, which is similar to a design variation onshore.

As the Holistic Network Design (HND) follows similar offshore principles in the design approach, it is anticipated that the provisions relating to N-1 outages will apply. If there is less redundancy than a compliant transmission system comparable to onshore specifications, there will be RoA on certain circuits should outages occur on those circuits. We do not expect that the generator will be compensated for outages on the relevant circuits in this situation. However, if there are outages or restrictions beyond the restrictions within the connection contracts, the usual commercial principles will also continue to apply, such as Bid Offer Acceptance or loss of access claims. The HND may diverge from existing arrangements where determining how restrictions are applied to affected generators in relation to the offshore transmission system.

Generally, later onshore connections may find themselves with more restrictions when compared to projects which have been connected for a longer period. This is due to the incremental nature of onshore generation, where there may be significant time between older and newer projects. In those scenarios there is justification for why a project which has applied and connected much later, and is potentially now in a more constrained area, may be subject to more restrictions. Within the HND, each project may be separated by a much shorter time in terms of their queue position, given the holistic nature of the design. Whilst it would be possible to apply a similar principle based on queue position, it may not be as straightforward or as justifiable.

Applying the queue-based principle to the offshore transmission system within the HND as the basis of determining restrictions would require a review of each regional design / geographic area and to work out the queue position of each of the generators in that region, rather than the queue position of each generator within the overall HND. Then the offshore restrictions of that regional design would need to be calculated with priority given to those who are the earliest in the queue. This could be problematic because it could conflict with the holistic nature of the HND, which is seeking to group projects where it results in a preferential solution. It would be difficult to study and provide updated connection contracts to projects that were in the same region but potentially have very different interim or enduring RoA for the offshore transmission system based on what could be a minimal difference in terms of the respective queue positions. There is a risk that this approach could adversely impact those generators who are later in the queue due to a higher level of curtailment than for those projects earlier in the queue.

Therefore, another approach could be to deviate from how onshore generators are treated and consider all projects within a particular HND region as having equal access to the offshore transmission system in that region. This would remove the notion of a queue position offshore within each region. Two principles could apply in such circumstances. Firstly, if possible, where there is a fault on the relevant part of the offshore transmission system, curtailment should be proportionately equal across all generators connected in that region of the offshore transmission system.

[34] A design variation is a lower security 'customer choice' type connection as defined within SQSS.

Secondly, in the more complex areas such as the East Coast Region, as per Figure 4, there may be some circumstances where all parties may not simply be curtailed to the same percentage in the event of any one fault. In this scenario, more detailed studies would need to be carried out to determine the impact of an outage on each part of the regional design to calculate what the maximum available capacity to export would be for all affected generators. In these instances, and in certain outages, some generators may have to be curtailed down to 50 per cent of their capacity whilst others could retain closer to 100 per cent of their capacity depending on where the fault occurs, the cable ratings of the route back to export, etc. However, it is not expected that any one generator will need to be curtailed to below 50 per cent of their capacity due to an outage, which keeps the offshore system in line with the existing standards. As such, there would still be no compensation for generators in these outage conditions.

It is worth noting that the onshore Transmission Owners (TOs) will continue to stipulate RoAs (if any) for each of the generators in scope for the HND as usual in respect of the onshore transmission system.

Further consideration will be required in relation to the RoAs in the event that the HND follow up design process (or subsequent network change) impacts on the access rights of those parties connected to any of the coordinated regional designs within the HND recommendations. Whichever approach is taken will need to be extended to also apply to any later connecting generators where they are to connect (directly or indirectly) to the system identified within the HND recommendations.

In both cases the timing of connections may have an impact on RoAs as a generator could potentially be provided with an earlier connection date where not all the reinforcement works have been delivered, meaning they could initially have interim RoA until all required works have been delivered. Conversely, more than one generator could connect as planned where a primary generator could have fewer initial RoAs in their connection contract and they could then have more restrictions once the subsequent generation connects.

Depending on the connection design and location, any given generator could be subject to all the above meaning their access rights and could change more frequently than is currently the norm, depending on the approach taken in the connection contract update programme based on the HND. There may need to be additional clauses or other relevant changes made to the connection contracts to reflect these possibilities. However, this will need to be looked at on a case-by-case basis.

In summary, for non-radial offshore transmission system within the HND, there could be a case for not following the existing principles for administering access rights based purely on queue position. This is partly as that could have a detrimental effect on the viability of any subsequent generator(s) in the regional design, where there has been a centralised design process. Whilst requiring further consideration, it could therefore be more appropriate as a result of the HND to attribute any offshore restrictions proportionally across all generators in the regional design rather than providing for them sequentially and incrementally as would be the case under the onshore approach where generators later in the queue can have more onerous RoAs than earlier generators.

However, how such an alternative approach to RoAs offshore could work and be implemented requires further planning and engagement. For example, we need to consider options related to codification, guidance, integration between offshore and onshore, connection contracts, etc. The above therefore describes some optionality and initial thinking on what a preferred approach to RoAs could be, and the consequences of lost or reduced access to the offshore transmission system within the HND.

Q12 Do you think that retaining the existing queue-based principle for offshore RoAs would be a material issue? If so, in principle, would you support the alternative approach to offshore RoAs? Do you have any further alternative proposals? Please explain your rationale.

8.2 Connect and Manage

As the HND recommendations do not have any Multi-Purpose Interconnectors included the question of Connect and Manage versus Invest and Connect does not need to be considered for the HND. Therefore, the Connect and Manage principles can be applied as per the current methodology, but there are two potential considerations in relation to the HND recommendations as follows.

The first consideration is that Connect and Manage does not extend to offshore transmission system or Offshore Transmission System Development User Works (OTSDUW) so when updating connection contracts in the connection contract update programme (as per Section 9) we will need to determine which offshore works are required prior to the connection of which offshore developers, and the implications of that in terms of access rights and RoAs, as per Section 8.1. We are aware of no plans to extend Connect and Manage arrangements to apply to offshore transmission system or OTSDUW.

The second consideration is that further work may be required by the TOs and/or ESO to fully specify the (onshore) Enabling Works for relevant connection contracts and how this then interacts with other processes, such as in relation to SQSS Derogations. More specifically, the approach the process has taken to the HND recommendations could potentially result in a non-standard approach to Enabling Works in some cases. This will be further considered in the connection contract update programme.

8.3 User Commitment (UC)

UC is the way generators (and other relevant parties such as interconnectors) are liable for and secure the transmission works required to connect their projects to the NETS[35].

Generators are liable for Attributable Works and a Wider Cancellation Charge upon termination or reduction in capacity, subject to a Strategic Investment Factor (SIF), a Local Asset Reuse Factor (LARF) and a Distance Factor (DF). Generators then secure a portion (which can be up to 100 per cent) of their liability depending on factors such as the completion date and key consents but remain liable for their total liability as outlined in their current bi-annual statements.

Attributable Works are defined as the transmission works which are required to connect the generator to an existing Main Integrated Transmission System (MITS) Node, as defined in CUSC Section 11.

The wider liability is a zonal £ per MW charge. These charges are published annually and are calculated from the apportionment of wider load related and non-load related capital expenditure across system boundaries and then mapped to generation zones.

The SIF applies to limit the attributable liability to the proportion of the investment that the generator has triggered. This factor ensures that the generator is not liable for more than their proportion should the TO build a component with greater capability than has been requested. The LARF is an estimate of what percentage of the attributable works component could be reused should the generator cancel their project. The DF is where the nearest MITS is not the connection MITS, and where the attributable works will be the pro rata share of the transmission capacity to connect the project to the nearest suitable MITS on the transmission network.

The general principle of UC is that whilst the project remains liable for their calculated share of the total costs incurred at any given time, they only secure a portion of that liability depending on how close their project is to its completion date. For example, the Wider Cancellation Charge only starts applying once the project hits the Trigger Date, which is 1 April three financial years before the year of connection. Therefore, if a project is due to connect in December 2030, the Trigger Date would be 1 April 2027.

The Trigger Date is the point at which costs are expected to ramp up, but after the Trigger Date the project only secures a portion of the total liabilities. This differs at Distribution and Transmission and is dependent on whether the project has achieved key consents.

Overview of current methodology (offshore)

The current UC methodology is based on an integrated onshore network and a radial offshore network. Therefore, after the brief summary of how UC works now for offshore generation the main part of this section then explores how UC could be applied to the HND recommendations on both the onshore and offshore transmission system.

Generator build (radial)

The generator is liable for and secures TO works through UC principles i.e., Attributable Works subject to SIF, LARF and DF and a Wider Cancellation Charge calculated via a zonal tariff on a £ per MW basis, when past the Trigger Date.

The generator then self-secures the OTSDUW, which will eventually be owned and operated by an Offshore Transmission Owner (OFTO).

OFTO build (radial)

The generator is liable for and secures TO works through UC principles i.e., Attributable Works subject to SIF, LARF and DF and a Wider Cancellation Charge calculated via a zonal tariff on a £ per MW basis, when past the Trigger Date.

[35] More detail can be found in our *UC Guidance Document* - www.nationalgrideso.com/document/188276/download

The generator is also liable for and secures the offshore construction works, which in this case are built by an OFTO through UC principles i.e., Attributable Works subject to SIF, LARF and DF and a Wider Cancellation Charge calculated via a zonal tariff on a £ per MW basis, when past the Trigger Date.

In this scenario, the ESO combines the two sources of securities data - both TO and OFTO - and passes the total liability onto the generator to secure.

Until an OFTO is appointed for the build stage, all previous stages such as detailed network design, consenting, etc, will be carried out by the generator. Those costs are therefore self-secured by the generator until the OFTO has been appointed and is able to provide the relevant information to the ESO as above.

Anticipatory Investment (AI) and UC

Ofgem's minded-to decision in relation to the Early Opportunities Workstream, which is subject to consultation, re-introduces a topic previously considered in relation to UC; AI[36]. This is investment in offshore transmission infrastructure to support the later connection of a specific offshore development or developments, as described in Section 3.10. The impact of this on UC is considered below and the impact on network charging is also considered in Section 7.10.

AI and UC in relation to PT2030, following the Early Opportunities approach to UC

Ofgem discusses a primary generator building the offshore transmission system and how they continue to self-secure the total costs. This is the portion of the offshore transmission system that is for their own use, as well as any additional investment for known subsequent generation as AI.

The early-stage assessment process proposed by Ofgem could provide the indicative non-AI proportions of the investment by the primary generator, as well as the AI Cost Gap. Although the cost assessment process to identify final values remains at a later date, the indicative values from the early-stage assessment could be used for UC purposes.

UC arrangements would then be extended to cover the AI Cost Gap for the subsequent generator(s) until their connection date. The UC risk value associated with the subsequent generation could either be secured in full by the subsequent generator(s) or be shared with consumers via extended UC arrangements. The primary generator would also continue to self-secure the total value (including AI) until the cost assessment process concludes at a later date.

If the same principle applies to the PT2030 workstream, as is identified to apply for Early Opportunities, then UC could work for at least some of the design within the HND recommendations, as follows:

- Ofgem determines what the non-AI value is for the primary generator and what the AI value is for the subsequent generator(s) and provides those values to the ESO. The ESO could take those values and apply UC principles to them (i.e., SIF, LARF, etc) thus extending out the UC principles offshore for AI related to the subsequent generator(s). This would split the risk between the subsequent generator(s) and consumers because consumers would pick up the risk on the delta between what the subsequent generator(s) will be liable for and securing, and the total AI value approved by Ofgem. For example, if the subsequent generator(s) terminated and the difference between the liability and the security could not be recovered from the subsequent generator(s) due to reasons such as them entering into administration.
- In terms of changes to the current UC arrangements within codes, there would need to be changes to CUSC Section 15 to reflect the fact that the subsequent generator(s) become liable for and secure works which ordinarily would not be covered under CUSC Section 15 i.e., the AI Cost Gap value. There would also likely be changes to address certain process additions. For example, i) Ofgem being the provider of certain information, such as the AI value for the subsequent generator(s) via an early-assessment process, and ii) the codification of which party would be determining the SIF and LARF values associated with the AI works. At this stage it would be prudent to review the SIF methodology to see whether this would lead to more risk being transferred from the subsequent generator(s) to consumers than would be desirable based on the current approach to the calculations.
- The discussion on SIF and LARF in relation to AI will not be applicable if the Ofgem minded to position is intending that the subsequent generator(s) is/are fully liable for and securing the AI Cost Gap.

[36] www.nationalgrideso.com/electricity-transmission/document/50476/download

AI and UC in relation to PT2030, not following Early Opportunities approach to UC

An alternative way of treating UC for PT2030 could be to extend out the existing UC concepts in full to both the primary generator and the subsequent generator(s). The OTSDUW related to both the primary generator and the subsequent generator(s) could become Attributable Works for those parties, but with the subsequent generator(s) then becoming liable for and securing the AI Cost Gap, and not the primary generator.

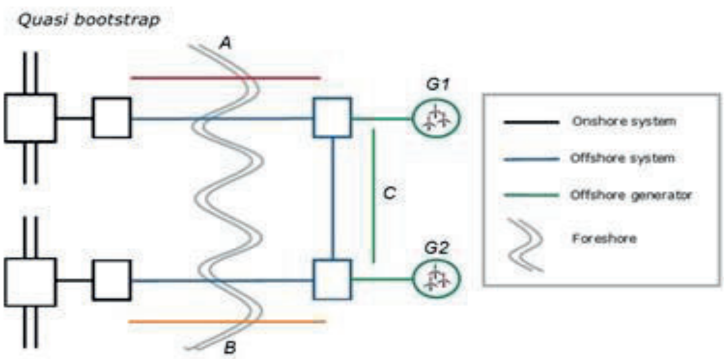
There could potentially also be an arrangement akin to TO Final Sums for the party (or parties) delivering shared offshore infrastructure. Whilst this could be an option it would lead to greater changes and complexities and would also likely pass additional cost risk to consumers when compared to the Early Opportunities approach above. However, it could result in a more consistent approach to UC between the primary generator and the subsequent generator(s) and between onshore and offshore arrangements. Therefore, this option would need further consideration to determine whether suitable, or whether the Early Opportunities related changes would remain sufficient for the HND recommendations.

This is briefly discussed in relation different network design configurations as follows.

Shared OFTO (coordinated)

An assumption in this model could be that the primary generator builds the entire shared offshore transmission system, but that may not necessarily be the case. This will be on a case-by-case basis and will also depend on the ownership boundaries. However, in certain cases the subsequent generator(s) may build a proportion of the offshore transmission system such as a subsequent generation spur to the offshore substation constructed by the primary generator. This network design could create complexity which would likely require some form of separation between the offshore transmission system building entity within the primary generator, and their own generating entity, if UC arrangements were extended offshore in full to both the primary generator and the subsequent generator(s). This would likely lead to a complex contracting and securities arrangement, which could be argued would become a potential issue. Such an arrangement doesn't currently exist and would need careful consideration as to how to best delineate rights and responsibilities between the offshore transmission system building and the generating parts of the primary generator to avoid perceived or actual conflicts of interest. This is because the primary generator, and the subsequent generator(s) if building shared infrastructure, could be both parties providing the numbers to the ESO for liability and security values to be calculated for each other. Both would then become liable for and secure based on those numbers.

Quasi bootstrap (coordinated)



The same principles as above would apply here, but this model has some specific complications. If we assume that the whole of the Quasi Bootstrap is for the purpose of the primary generator and the subsequent generator only and not for any boundary flow benefits, then Circuit A or Circuit B could potentially only be needed for the primary generator and the subsequent generator respectively, for what would effectively be two radial connections. However, where Circuit C is for the benefit of both generators to allow them to export via both Circuit A and Circuit B, then those two circuits become for the benefit of each other as the primary generator cannot flow via Circuit C to reach the onshore system unless it also uses Circuit B and vice versa.

However, if Circuit C is for both generators and for boundary flow benefits, both parties should arguably not be fully liable for and securing the entire cost and this adds in a further complication to UC / AI calculations. Whether the SIF and LARF calculations are enough to determine the difference remains to be seen. Therefore, if UC arrangements were extended offshore in full to this model, it would need further consideration to ensure the correct values are allocated to the correct parties for liability and security values. It would also need to consider any costs which were for wider system benefits, as well as for both generators.

The same complexity as discussed in the shared OFTO model could also apply here. If the offshore transmission system is built in part by both the primary generator and the subsequent generator(s), it would likely lead to complex contracting and security arrangements. There could also need to be some form of separation between offshore transmission system building and generating parts of the primary generator to avoid perceived or actual conflicts of interest.

Additionally, a circumstance could potentially arise where the nearest MITS for the primary generator is in one Electricity Ten Year Statement (ETYS) zone, and the nearest MITS for the secondary generator(s) is in another ETYS zone. For the purposes of the UC Wider Cancellation Charge calculation, the most straightforward solution would be for each generator to be liable for and secure their respective wider charges based on their nearest MITS in their nearest ETYS zone. However, further industry engagement would be needed to determine whether this is indeed the most appropriate solution.

Given the potential additional complexity, it is likely that further work would be required to identify the extent to which existing UC arrangements would need to change to facilitate these network designs. This is especially true due to some of the above and the potential for AI to be treated separately within calculations, which is not currently something in the arrangements onshore.

TO bootstrap (coordinated)

This network would remain part of the onshore transmission system. Clarity would be needed regarding Ofgem’s view as to whether AI applies in this scenario. If AI policy changes are only intended to apply to offshore transmission, then no changes to the existing UC principles are needed here and the status quo would remain applicable. If it is intended that AI is also a concept for onshore transmission system in relation to the HND, the TO or another relevant party would need to provide information to facilitate UC arrangements.

For example, there is currently a possibility that some of the North West Region network in Figure 3 could become Attributable Works for the offshore wind farm in Scotland under the existing UC arrangements if some of that network is identified to be onshore rather than offshore transmission system.

Additional points

If the subsequent generator(s) connect several years after the primary generator, the liability and security would be geared for the completion date of the primary generator. The subsequent generator(s) may therefore have concerns related to securing their portion of the UC liability, as they will likely be much further back in terms of their Financial Investment Decision(s). On a related point, an amendment could be made to make it clearer that even though the Attributable Works and any AI had been completed by the primary generator the subsequent generator(s) would still be liable for and secure those works until their own connection date.

An additional complication is the potential issue of the primary generator incurring delays on the offshore transmission system build to the detriment of the connection date of the subsequent generator(s). Whilst this is straying into other concepts such as queue management, there could be circumstances where a subsequent generator is securing due to the primary generator undertaking offshore delivery activities, whilst being delayed by the primary generator. This situation could be further complicated if both were undertaking some of those delivery activities and each were potentially impacting upon the other one. This is further discussed in Section 8.4, but potentially has UC implications. For example, would these works be classed similarly to onshore works where delays alter the Trigger Date, or would they be classed similarly to User Works or OTSDUW where delays do not alter the Trigger Date.

It would seem unreasonable to not allow the shifting of the Trigger Date of the generator who has incurred a delay due to works undertaken by another generator. This potentially needs to be reflected in additional and reciprocal arrangements between the offshore transmission system building and generating entities of the primary generator, and the ESO where necessary. In turn there could be related arrangements between the ESO and the subsequent generator(s), such as via connection contracts.

It is envisaged that terminations would follow the same principles as is currently the case i.e., securities are held by the ESO, and if any party terminates the ESO would wait for the termination reports from the relevant entity or entities before following the existing terminations process. However, difficulties could arise if the party building the offshore transmission is the terminating generator. Notwithstanding the UC liabilities, this raises questions on whether the terminating generating party is able to continue to build the offshore transmission system, whether the build is transferred to the subsequent generator(s) (or a TO, or another party) or whether this termination strands other network needs. For example, the connection of the subsequent generator(s).

If UC arrangements had been extended offshore in full it also raises questions as to whether the flow of securities should go from the generating entity that is terminating, to the ESO and then partially back to the offshore transmission system building entity, which is then potentially the same overall entity. This could be the case if the TO Final Sums elements of existing UC arrangements were applied and would need additional safeguards within codes, contracts and/or the terminations process.

As a rule, it is therefore important that any amended UC arrangements ensure it is clear who is responsible for providing data to whom and when, and how such data is assured. This is so that the ESO can correctly calculate UC liabilities to request the correct security from both the primary generator and the subsequent generator(s). It is likely new processes (and potentially system changes) could be required to facilitate any such changes.

As there are now initial minded-to positions in relation to UC / AI and the offshore delivery model for the HND, we will participate in the Ofgem consultation and carry out additional industry engagement to further explore the main challenges, before progressing with the necessary code modifications related to UC.

Q13 In relation to the Early Opportunities proposal do you believe AI liability and security should be passed to the subsequent generator(s) in full until the connection date or should there be consumer sharing? For example, via existing UC principles such as the SIF and/or the LARF. Please explain your rationale.

Q14 Do you support the Early Opportunities proposal, the alternate proposal, or favour another proposal, for UC? Please explain your rationale.

8.4 Queue management

A Queue Management CUSC modification seeks to alleviate delays once connection offers are signed as customers wait for their capacity to be made available. This can occur where customers experience challenges in getting their project ready in line with the agreed programme but are able to keep their queue position. This prevents other generators who can connect but are further down the queue position from connecting earlier / on time. The scoping for this code modification will begin over the course of this year with the introduction of remedies to allow for projects in a better state of readiness to move up the queue and projects which are in significant delay to move down the queue or be terminated for persistent breaches for a more effective connection timeline. It is anticipated that all the queue management proposals shall apply to projects in scope for the HND once implemented. There will be some HND and offshore delivery model specific issues which may need further consideration through this modification and implementation process.

For example, it is expected that if a primary generator is building the coordinated offshore transmission system and there are delays, any subsequent generator(s) should not be impacted by those delays for queue management purposes, as they would be outside of their reasonable control. However, this is a new scenario which does not currently occur and is a result of the preferred offshore delivery model for coordinated offshore transmission system.

The primary generator will likely be obligated to build the offshore transmission system in a compliant and efficient manner, so any delays could be reviewed using criteria commensurate to that of a TO delay in similar circumstances. However, what will need to be worked through will be the obligations of the primary generators (to build efficiently but cognisant of the fact that reasonable delays can occur) versus any rights and remedies of the subsequent generator(s) to not have unreasonable delays to their project, such as liquidated damages.

What remains unclear is what would happen if there were persistent delays by the primary generator i.e., whether the offshore transmission system build would be de-scoped from the primary generator, whether liquidated damages would apply, or whether their own connection date would be at risk if they were found to be in breach of their responsibilities in their role delivering the offshore transmission system. Some of the risks could be addressed via queue management proposals, but many may need to be considered in the context of the implementation of the offshore delivery model arrangements, possibly including via use of new rights and obligations within connections contracts and/or codes. Some or all of the arrangements may also be left to developers to agree on a commercial basis. In addition, we will need to remain mindful of comparable arrangements for generators in the context of the current onshore arrangements where TOs are delivering works and connection dates.

A further complication could arise, as alluded to in Section 8.3, where both generators are responsible for building different parts of the same region within the offshore transmission system, whereby each party could have potential delay claims against the other one.

The extent to which these issues are relevant will be determined once the sequencing of the HND works is known and attributed to TOs and developers. It is expected that due to queue management principles, generators may have the ability to connect earlier than first anticipated due to the re-positioning or termination of delayed generators, if and where queue management arrangements have been implemented. However, any earlier connection will also depend on the specific network circumstances in the vicinity of the connection.

The HND and offshore delivery model specific issues related to queue management will be included and considered as part of the broader queue management modification and a separate HND and offshore delivery model related modification is not recommended.

Q15 What do you see as the biggest risks and challenges in relation to queue management and the proposed offshore delivery model for the HND? Are there any HND specific issues that need to be addressed in any queue management code modification? Please explain your rationale.

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9 Connection contract update programme

9.1 Connections and connection contracts

All generation and demand projects directly connected to the National Electricity Transmission System (NETS), including to the offshore transmission system, hold a Bilateral Connection Agreement (BCA) with the ESO. A generation BCA sets out (amongst other things) the Transmission Entry Capacity (TEC) a project holds, and this is then the basis of their network charges. It also sets out the circumstances in which system access can be removed or reduced, as well as some of the other technical and commercial information and conditions related to the connection.

Prior to the connection date for those projects, a Construction Agreement is also in place with the ESO[37]. Primarily this sets out the required transmission reinforcement works required prior to the connection and the associated connection date. It includes information related to the user commitment liabilities and securities. For offshore wind projects, these agreements are 'generator build' style connection contracts.

As we set out in our open letter in January 2022[38], for projects in scope for the HND and holding a connection contract, there will be three different triggers for change as follows. We noted that we expect there could be change related to i) HND recommendations on the network design, ii) because of expected changes to codes and standards as a result of the HND recommendations, and iii) the offshore delivery model to be utilised for the delivery of those HND recommendations.

As we now have the HND recommendations, our initial views on codes and standards as a result, and the Ofgem minded-to decision on the offshore delivery model, we have started to consider the impact on the connection contracts. Over the past few weeks, we have been considering the impact on the connection contracts in a preparatory stage and we are now moving into a period of considering actual changes to specific in scope developer contracts with the relevant TOs. We are planning to schedule time with impacted developers to start to consider these changes.

Our aim remains to provide impacted developers with an Agreement to Vary in Autumn 2022, but this remains subject to certain pre-requisites and caveats. These timescales are subject to further clarity being provided, and this may result in connection contract updates extending beyond Autumn 2022[39]. We will be in touch with developers in the near future to provide information on when to expect their Agreement to Vary from the ESO.

The exception to the above is in relation to the Celtic Sea Region within the HND. In the open letter referenced above, we noted that it 'may become apparent that an alternative connection contract update approach can be taken for Celtic Sea developers as the HND process progresses.' Due to the HND recommendations and our plans to further consider the Celtic Sea Region within the HND follow up design process, we are now only going to update these connection contracts in the above timescales for offshore developers in this region by exception. Therefore, we will be in touch directly with any Celtic Sea developers (if any) in the region where a connection contract update is required in the above timescales, and in all other cases connection contracts will be updated once the HND follow up design exercise has concluded and/or once leases for the region have been awarded.

A further regional specificity relates to developers with connection contracts who participated in the ScotWind leasing round and were unsuccessful. In the open letter referenced above, we noted that we would take steps to terminate these connection contracts. We stated that we were in the process of identifying the most suitable time and mechanism to action such terminations and that we would be in contact with unsuccessful developers who hold a connection contract to discuss the termination process before any connection contract terminations. We have now considered the above and we will work with unsuccessful developers to terminate connection contracts as soon as reasonably practicable. Any developer successful in the ScotWind clearing process will need to submit a new connection application to the ESO in due course.

9.2 Preparatory work and tentative views

Based upon our preparatory work related to the connection contract update programme to date we have summarised some of the key potential changes and interactions we have found to date as follows.

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[37] There is also a concept of a Transmission Related Agreement, and an Accession Agreement, in relation to connections but we do not believe they are impacted in relation to these proposals.
[38] www.nationalgrideso.com/document/230851/download
[39] The connection contract update programme will also need to consider any potential consequential connection contract impacts for developers which are not included within the HND.

Generator commissioning clause

With the offshore delivery model preferred by Ofgem and no known plans to change legislation in respect of the generator commissioning clause in the context of the issue considered in Section 4, there is potential in some of the HND for offshore transmission assets required by one developer to be delivered by another one. For example, in Figure 4 you can see the potential for two different developers to be sharing a single circuit to a common interface site. In such circumstances, one of those developers will need to become the primary developer to design, consent and deliver those offshore transmission assets, whereas the other will become the subsequent generator and now rely on them being delivered by the primary generator.

Under the standard generator build arrangements, a single generator would normally design, consent, and construct their own radial Offshore Transmission System User Assets (OTSUA) by undertaking the relevant Offshore Transmission System Development User Works (OTSDUW). Once the OTSDUW is completed and the OTSUA has transferred to an Offshore Transmission Owner (OFTO) at the OTSUA Transfer Time those assets will become part of the National Electricity Transmission System (NETS).

If a subsequent developer is to connect to the OTSUA prior to the OTSUA Transfer Time then whilst they are technically connecting to an offshore transmission system, it is owned and operated by the first generator as the OTSUA Transfer Time has not occurred and so it is not part of the NETS.

Therefore, for any developer in the HND which has a connection date within 18 months of the connection date of another, earlier connecting primary developer, where there is shared infrastructure being delivered by that primary developer, there will likely be a need for connection contract specific considerations.

Whilst we are yet to determine exactly what connection contract changes are required for such developers, we will develop our thinking further in advance of updating connection contracts, and we will engage with impacted stakeholders. As above, initial thinking on options for such changes can be found in Section 4.2.

User Commitment (UC)

As can be seen from Section 8.3 we expect that any coordinated offshore design within the HND will trigger changes to UC arrangements. As connection contracts include information and processes based on CUSC Section 15 and associated ‘exhibits’ to the CUSC then the connection contracts, associated documentation and CUSC Section 15 are likely to be misaligned with policy direction for a period of time.

Therefore, prior to the conclusion of any code change related to UC we expect that relevant connection contracts will need to include presumptive provisions related to the outcome of future code modifications and/or targeted reopeners to amend connection contracts to align with the outcome of a code modification. Whilst we are yet to determine exactly what such presumptive provisions and/or targeted reopeners could look like in the connection contracts, we will develop our thinking in advance of updating connection contracts and we will engage with relevant stakeholders.

The alternative to including presumptive provisions would be to leave all OTSDUW related to shared offshore infrastructure as being outside the scope of the UC arrangements and this would leave any primary generator with all liability for such works via the self-securing arrangements currently in place.

Our view is that this would not be equitable in light of the expected changes described in Section 8.3 and so the subsequent generator(s) should be taking on some of the liability and associated security associated with any shared offshore infrastructure from the date of connection contracts being updated to reflect the outcome of the HND.

To further illustrate the above, a presumptive provision could be to work on the basis that the proposed gateway assessment will define the AI value and a code change will then allow the definition of liability and associated security in respect of that AI value for the subsequent generators(s). Until that point in time, we could assume the expected AI value, the expected liability, and the expected security requirements for the subsequent generator(s). We could also seek to restrict the ability of the subsequent generator(s) to fix their liability until such time the gateway assessment has concluded.

A targeted reopener could be to simply state that the ESO can amend the connection contract in future insofar as that is necessary to accurately reflect the updated provisions in CUSC Section 15 as a result of any Ofgem decision on relevant changes to codes.

Network charging

As connection contracts do not include specific references to the calculation of network charges, other than in relation to transmission connection asset charges, we do not believe any changes to connection contracts will be required as a result to the potential network charging related code changes identified in Section 7.

Subject to ownership boundary clarification in respect of the potential for there to be transmission connection assets at the offshore connection site, it is also unlikely that connection contracts will need to be amended in respect of transmission connection asset charges.

Construction stages, access rights and restrictions on availability

To allow connection contracts to be updated, any OTSDUW staging will need to be identified to enable restrictions on availability to be identified and included within connection contracts. This assumes that access rights remain broadly unchanged with offshore generators having a defined TEC from a given connection date or a staged set of connection dates.

Prior to this it will be necessary to have defined which elements of the HND are to ultimately become offshore transmission system. This will allow the entire scope of the OTSDUW within the HND to be identified, from which it will be possible to determine the staging of construction and as a result the staging of access rights and restrictions on availability.

It will also be important that any OTSDUW is allocated to a specific generator i.e., which OTSDUW will be included in which connection contracts, which is solely related to the primary generator, and which is shared works related to the subsequent generator(s). This information will facilitate the correct OTSDUW being included within the correct connection contracts, whether staged or otherwise.

This will also be applicable to any works within the HND which are to be onshore transmission system and the TOs are expected to provide corresponding information for the onshore transmission system.

With such information the ESO will be able to include an overall position in connection contracts in relation to access rights and restrictions on availability in respect of the NETS, including any staged access and restrictions on availability associated with the NETS.

Offshore delivery responsibility

Linked to the above, there is also a question of how the party to design and deliver given stages of the HND is to be identified so that the correct works can be included in the correct connection contracts in the correct way. This will allow us to understand who the primary generator will be for each part of the HND which is to be designated as the future coordinated offshore transmission system.

The Ofgem minded-to consultation on offshore delivery models states that Ofgem will work will the ESO and developers once the HND is finalised to agree how any coordinated offshore transmission system is to be delivered in respect of the HND. Such agreement will be required to allow connection contracts to be updated, including the identification of onshore and both radial and non-radial offshore transmission system in the HND.

Technical appendices

At this stage we have not identified the specific changes that will be required to technical appendices within connection contracts. This in part depends on the identified location of the offshore grid entry point and the transmission interface point(s) for each of the generators within the HND. In radial designs we expect the arrangements to be mostly as standard and for coordinated designs there could be specific considerations, such as those related to the points discussed in respect of the STC and Grid Code in Section 6.

Whilst technical changes to STC Section K and Grid Code as a result of the HND require further consideration, it is unlikely that there will be material changes to the technical appendices. It is more likely that the network studies required by the technical appendices could result in design specific requirements.

For example, the harmonic elements within Appendix F and Appendix OF to the connection contracts could be more complicated for a coordinated offshore transmission system when compared to a radial one. The reason being that there will be more than one offshore generator impacting the transmission interface point(s) on the onshore transmission system.

Accelerated connections

As can be seen in the UK Government's April 2022 British Energy Security Strategy[40], there are ambitions to shorten consenting timescales. When it comes to updating connection contracts in future, there is the possibility that some of the connection dates related to the HND could potentially be based on delivery timescales which factor in some of these anticipated shorter consenting timescales, rather than the standard timescales assumed when considering connection dates. Therefore, for any projects where an assumed time saving is identified and applied, there is potentially a need for a contractual reopener related to any associated risks or assumptions. For example, if the time saving does not materialise in practice, in what circumstances does this delay the connection date, if any? Where does the risk associated with non-delivery in advanced timescales sit, such as developers, TOs, consumers, another party, or a combination?

Prior to the need for, and scope and duration of, such a contractual reopener being confirmed and included within connection contracts, further exploratory work is required by the ESO. In the event such a contractual reopener is to be included within some or all the Agreements to Vary related to relevant in scope projects, we will discuss this further with developers once more is known in future.

Connect and Manage

Connect and Manage does not extend to OTSDUW or the offshore transmission system. Therefore, we need to identify a suitable means to differentiate OTSDUW required prior to the connection of a given developer and OTSDUW that can be completed after the connection of that developer, akin to Enabling Works. Without a mechanism to do so, and without Connect and Manage offshore, all interconnected OTSDUW could be viewed as being required for all interconnected offshore developers. When we update connection contracts, we expect that we will be able to include the minimum necessary works offshore to allow connection and we will aim to not include all such works where possible.

In addition, we will need to work with TOs to specify the Enabling Works for each developer and how those works may interact with existing processes, such as for Security and Quality of Supply Standard derogations. We expect that when we update connection contracts, we will be able to include any such works.

Both sets of these necessary works - the Enabling Works and OTSDUW - will therefore inform the contracted connection date which will have been communicated to developers as soon as possible in advance. This topic is linked to the above section on 'Construction stages, access rights and restrictions on availability'.

Connections and Infrastructure Options Note (CION) and seabed leasing clauses

Most, if not all connection contracts with the in scope developers will have CION clauses included within their connection contracts. They will also likely have seabed leasing clauses included in reference to what happens if a developer is unsuccessful in a leasing round. We are likely to amend the CION clauses to refer to the HND and to remove seabed leasing clauses where they are no longer applicable for specific developers. This will ensure that these clauses are only included insofar as they are required and that they are up to date in relation to current approaches.

Q16 Do you feel that the above is a reasonable list of the key potential changes and interactions between the HND recommendations, the minded-to decision on the offshore delivery model and the connection contracts? If not, what do you feel are the omissions?

[40] www.gov.uk/government/publications/british-energy-security-strategy/british-energy-security-strategy

10 Conclusions and next steps

10.1 Overview

Our primary conclusion, based on the Holistic Network Design (HND) recommendations and the minded-to decisions from Ofgem for both the Early Opportunities workstream and offshore delivery model, is that further work and engagement is required to determine the necessary changes to codes, standards, and licences.

As can be seen from the above, there are several areas where changes are likely to be necessary, many of which may have interactions with our planned connection contract update programme.

This recommendation report therefore makes some more specific recommendations, supported by our recent publications on the Security and Quality of Supply Standards (SQSS) and Early Opportunities. In these, two modifications related to the SQSS review (and necessary for the HND recommendations) are currently in progress. Three network charging code modifications related to the Early Opportunities workstream that are necessary for the HND recommendations have already been recommended as being required and are now actively being developed and engaged upon with stakeholders.

However, this recommendation report is providing a broader range of recommendations. In some areas we are more confident that a code or standard change will definitely be necessary, and we have therefore provided a more definitive position. In other areas we are still developing our thinking and we have not yet formed a view and made a recommendation. Our overarching recommendation is therefore that this report is used as a tool to gain further stakeholder views on our initial thinking and to highlight areas where code, standard and licence modifications may be required in future.

Further development of and engagement on any of the necessary or potentially necessary changes can therefore be undertaken prior to changes being progressed via code and standard modifications. In some cases, we also do not believe code or standard modifications related to the HND should be progressed until formal decisions have been published by Ofgem further to the above two minded-to policy decisions.

We also note that the current direction of thought regarding the progressing of code modifications relating to the HND is to follow the open governance process. It is too early to form a definitive view on the most suitable mechanism for progressing code modifications related to the HND, in part, due to the current uncertainty regarding the total scale of required code changes. However, it should be noted that progressing via open governance is highly likely and would not be without risk considering the potential timescales to deliver code and standard changes via this route. This is coupled with any proposed changes being subject to the usual panel prioritisation process at a time when there is already a significant number of code and standard changes being raised in other areas. Subject to the emerging scale of changes required to facilitate the delivery of the HND, we therefore believe that the mechanism for delivering change should be kept under review, although at this stage it appears that open governance is the only available option. Therefore, our aim for code and standard modifications will be to avoid unnecessary changes, and for pace and pragmatism where change is required to facilitate the HND recommendations.

The next steps in relation to the content of this recommendation report, and any necessary changes related to the HND recommendations and the associated offshore delivery model changes are as follows.

10.2 HND connection contract update programme

As per Section 9, preparatory work on pro forma type changes to connection contracts will continue to facilitate an Agreement to Vary being provided to relevant in scope developers in Autumn 2022. These dates remain subject to the stated caveats and pre-requisites. Therefore, these timescales are subject to further clarity being provided, and this may result in connection contract updates extending beyond Autumn 2022.

We are planning for a reasonable period of time, potentially three months, for discussion and acceptance of the Agreement to Vary once it is made available. We would expect that any Agreement to Vary will be able to be referred to Ofgem.

In parallel, as part of our broader stakeholder engagement after the HND, we will potentially arrange one or more targeted workshops to explore some of the more challenging aspects of connection contract updates. For example, in relation to the generator commissioning clause implications for connection contracts as considered in Section 4. We will also commence tripartite discussions with relevant developers and Transmission Owners in Summer 2022.

10.3 HND code and standard modification update programme

As per Section 4, and Sections 6 to 8, there are several potential code and standard modifications required to facilitate the HND, including those related to the offshore delivery model related to the HND.

We would welcome feedback from stakeholders on the content of the recommendation report related to potential impacts on codes, standard and licences. Specifically, in light of the HND recommendations and/or the Ofgem minded-to decisions, whether we have identified and are starting to consider the right areas of potential change, including whether there are any material omissions.

We have asked key questions throughout this recommendation report, and we welcome feedback on those questions, or any other areas related to codes, standards, and licences. As licences are the remit of Ofgem we plan to share any feedback we receive on licences and any other relevant areas with Ofgem. If you do not want your response to be shared with Ofgem please make that clear to us. Please also make it clear if you do not want your response to be published on our website.

For the avoidance of doubt, in this report we are seeking feedback on the impact on codes, standard and licences of the HND recommendations and the preferred offshore delivery model within Ofgem's minded-to decision. We are not seeking feedback on the network design being recommended in the HND.

If you have feedback to share in response to our questions, or this report more generally, please send them in a format of your choosing to box.offshorecoord@nationalgrideso.com by Friday 12 August.

We plan to hold an industry webinar on Tuesday 19 July to talk through the content of this recommendation report and to take questions to help inform your response. Further information on this webinar will be available in the near future. We will also be attending code forums and panels throughout July or August 2022 to share key elements of this recommendation report.

Throughout Summer 2022, we will consider your feedback and use it to further develop our thinking on potential code and standard modifications. We note that some of the feedback could also potentially help to inform the content of the connection contract update programme. We also expect relevant policy decisions from Ofgem over the coming months and this will be fed into our plans for code and standard modifications.

We will also be arranging a suite of workshops/webinars throughout Summer 2022 to explore and discuss targeted aspects of this recommendation report in greater detail with interested stakeholders and experts. More information on these workshops/webinars will be provided in July 2022.

The above recommendation report consultation, subsequent workshops/webinars, policy decisions from Ofgem and developer tripartite discussions (via the connection contract update programme) will allow us to finalise a list of necessary code and standard modifications. We will then develop those modifications to the extent that they can be formally raised by the appropriate party, such as the ESO, via open governance.

We are currently expecting to start to raise higher priority code and standard modifications in Autumn 2022. However, if we identify any more urgent code and standard modifications via the above engagement process, we can explore more urgently developing and raising those modifications in Summer 2022.

A high-level pictorial of the above engagement approach can be found in Section 2.11.

Q17 Do you agree with this engagement approach and how would you like to be engaged regarding the code, standard and licence considerations outlined in this recommendation report?